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BEFORE THE PUBLIC UTILITIES COMMISSION OF THE

STATE OF CALIFORNIA

Order Instituting Rulemaking to Continue the Development of Rates and Infrastructure for Vehicle Electrification.	Rulemaking 18-12-006

JOINT COMPLIANCE FILING OF SOUTHERN CALIFORNIA EDISON COMPANY (U 338-E), SAN DIEGO GAS & ELECTRIC COMPANY (U 902 E), AND PACIFIC GAS AND ELECTRIC COMPANY (U 93 E) PURSUANT TO ORDERING PARAGRAPH 2 OF DECISION 16-06-011

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Dated: **March 31, 2021**

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STATE OF CALIFORNIA

Order Instituting Rulemaking to Continue the Development of Rates and Infrastructure for Vehicle Electrification.	Rulemaking 18-12-006

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Southern California Edison Company ("SCE"), San Diego Gas & Electric Company ("SDG&E") and Pacific Gas and Electric Company ("PG&E") hereby file[1] their Electric Vehicle Charging Infrastructure Cost Report as required by Ordering Paragraph 2 of Decision 16-06-011 and the Administrative Law Judge Ruling Amending the Load Research Report Deadline for 2020 and Beyond issued on January 6, 2020. The report is attached to this pleading.

1 Pursuant to Commission Rule 1.8(d), SDG&E and PG&E have authorized SCE to file the attached compliance report on their behalf.

Respectfully submitted,

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March 31, 2021

ATTACHMENT

Joint IOU Electric Vehicle Load Research and Charging Infrastructure Cost Report

9th Report Filed on March 31, 2021

Joint IOU Electric Vehicle Load Research and Charging Infrastructure Cost Report 9th Report[1] Filed on March 31, 2021

[1] The report filed in 2020 was named "Joint IOU Electric Vehicle Charging Infrastructure Report," as it did not include a Load Research component. The name is changed for this year to reflect the inclusion of both load research and charging infrastructure cost.

Table of Contents

I. Executive Summary

The Joint Investor-Owned Utility (IOU) Electric Vehicle (EV) Load Research and Charging Infrastructure Cost Report for 2020 (Report) examines EV customer charging behavior and service and distribution system upgrade costs related to EV load for California's three large investor-owned utilities (IOUs), including Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), and San Diego Gas & Electric Company (SDG&E), collectively the Joint IOUs. In this report, the Joint IOUs provide EV load and infrastructure costs by (1) pilot-programs and (2) rates or non-programs. An examination of EV charging behavior and EV charging infrastructure costs within the Joint IOUs' territories can provide useful insights on the IOUs' support in helping accelerate widespread transportation electrification (TE).

To help attain its climate and air quality goals, California has set correspondingly aggressive TE goals, as the transportation sector is the largest source of Greenhouse Gas (GHG) emissions in the state.[2] Senate Bill (SB) 350 established that "[a]dvanced clean vehicles and fuels are needed to reduce petroleum use, to meet air quality standards, to improve public health, and to achieve greenhouse gas emissions reduction goals,"[3] and required the Commission to direct electrical corporations to file applications for programs and investments to accelerate widespread TE.[4]

California's aggressive TE goals include Governor Brown's Executive Order (E.O.) B-48-18, which sets a target of five million zero emission vehicles (ZEVs) on California's roads by 2030 and requires installation of 250,000 public charging stations, including 10,000 direct current fast charging stations in operation by 2025. Additionally, on September 23, 2020, Governor Gavin Newsom issued Executive Order (E.O.) N-79-20, requiring the sale of all new passenger vehicles to be zero emission by 2035 and, where possible, directs all medium- and heavy-duty vehicles to be zero emission by 2045.

The IOUs have and will continue to play a critical role in TE infrastructure deployment through the IOUs' core business of delivering electricity, supporting the installation of utility-side infrastructure for EV charging, and in the development and implementation of strategically designed rate-payer funded pilots and programs that support the acceleration of TE.

A. IOU EV Adoption Forecasts

The EV market is evolving. New vehicle models with larger battery sizes, supporting increased charging levels and more choices for charging equipment, and charging services are entering

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[2] CARB, *California Greenhouse Gas Emissions for 2000 to 2018: Trends of Emissions and Other Indicators* (2020 Edition), p. 5.
https://ww3.arb.ca.gov/cc/inventory/pubs/reports/2000_2018/ghg_inventory_trends_00-18.pdf

[3] PU Code, § 740.12 (a)(1)(A).

[4] PU Code, § 740.12 (a)(1)(I)(2)(b).

the EV market. Some EV manufacturers and charging providers have also left the market. This product and service evolution will affect vehicle adoption, charging demand, and infrastructure costs and is expected to continue in the near term as the EV market grows and matures.

As of December 31, 2020, the IOUs estimate that more than 633,497 EVs were on the roads in their service territories. The number of light duty and medium- and heavy-duty EVs forecast to be operating in the IOUs service territories from 2021 through 2026 are provided in Table 1.

TABLE 1: IOU EV ADOPTION FORECASTS

	Light Duty EVs			**Medium- and Heavy-Duty EVs**		
Year	**PG&E**	**SCE**	**SDG&E**	**PG&E**	**SCE**	**SDG&E**
2021	332,083	326,886	57,820	732	969	N/A
2022	386,528	398,801	64,436	1,090	1,836	N/A
2023	457,989	500,847	71,051	1,697	3,386	N/A
2024	554,276	628,491	77,667	2,719	5,789	N/A
2025	689,947	741,619	84,283	4,448	9,120	N/A
2026	879,757	875,111	90,899	7,317	13,358	N/A

SCE's updated EV adoption forecast is lower than what was reported in 2020, due to assumption and methodology changes, which are described in Attachment 2, SCE's Table 1.

Each IOU may use a different methodology to forecast EVs in their service territory. Details on the methodology, as well as an expanded forecast, can be found in Table 1 of each IOUs' attachments submitted in conjunction with this report.

B. Revised IOU EV Load Research and Charging Infrastructure Cost Report

Since 2011, the IOUs have filed annual Load Research Reports focused on residential EV customer charging behavior and service distribution system upgrade costs related to residential EV load. On December 19, 2018, the California Public Utilities Commission (Commission or CPUC) issued Rulemaking (R.) 18-12-006, the Order Instituting Rulemaking to Continue the Development of Rates and Infrastructure for Vehicle Electrification (DRIVE OIR). Within the DRIVE OIR, Energy Division staff were directed to consider "whether Load Research Reports include all relevant data and whether or how to direct the IOUs to continue filing Load Research

Reports."[5] Additionally, the IOUs were directed to "incorporate cost data related to infrastructure needed to upgrade commercial customer sites where ZEVs (zero emission vehicles) are being deployed" into the Load Research Report.[6] To address these requirements, in 2019, the IOUs collaborated with the Energy Division staff to revise the Load Research Report. The renamed IOU EV Charging Infrastructure Cost Report eliminated load data, adopted a standard template for program and non-program infrastructure costs, and incorporated commercial upgrade costs.

In 2020, the Energy Division directed the IOUs to incorporate load data back into this Report. Accordingly, this Report includes data through December 2020 for residential and commercial EV load, project cost, service line and distribution system upgrades, and the current EV adoption forecasts of each IOU, all of which are discussed in further detail in the following sections.

The IOUs will continue to work closely with Energy Division to adjust the content and format of future reports as necessary based on feedback.

II. Background

On July 25, 2011, the Commission issued Decision (D.)11-07-029 (the Phase 2 Decision) in the Alternative-Fueled Vehicle Order Instituting Rulemaking (R.) 09-08-009 (AFV OIR), to evaluate policies and develop infrastructure sufficient to overcome barriers for the deployment and use of EVs in California. The Phase 2 Decision of the AFV OIR determined that EV load is new and permanent under Electric Rules 15 and 16 and adopted the interim policy of treating the residential EV charging costs that exceed the allowances in Rules 15 and 16 as common facility costs. The Phase 2 Decision also ordered California's IOUs, which includes PG&E, SDG&E, and SCE, to conduct research to examine EV customer charging behavior, as well as track service and distribution system upgrade costs related to EV load. The IOUs filed the first Joint IOU Electric Vehicle Load Research Report (Load Research Report) in December 2012. In D.13-06-014, issued July 3, 2013 (the First Extension Decision), the Commission extended the research for an additional three years[7] with reports to begin in December 2013.[8] The First Extension Decision also directed the Energy Division to work with stakeholders to revise the load research methodology.[9] In D.16-06-011, issued on June 13, 2016 (the Second Extension Decision), the Commission extended the interim policy of treating the residential electric vehicle charging

[5] R.18-12-006, Order Instituting Rulemaking to Continue the Development of Rates and Infrastructure for Vehicle Electrification and Closing Rulemaking 13-11-007, December 19, 2018, p. 15.
[6] Assigned Commissioner's Scoping Memo and Ruling, p. 13.
[7] D.13-06-014, p. 15.
[8] D.13-06-014, Ordering Paragraph 4.
[9] D.13-06-014, Ordering Paragraph 3.

costs that exceed the allowances in the Electric Rules 15 and 16 of the three IOUs as common facility costs for another three years, to June 30, 2019.[10] In addition, the annual filing requirement of the Load Research Reports was extended by another three years.

On December 19, 2018, the Commission issued the DRIVE OIR (R.18-12-006) and directed the Energy Division staff to consider "whether Load Research Reports include all relevant data and whether or how to direct the IOUs to continue filing Load Research Reports."[11] The subsequent Scoping Memo, issued May 2, 2019, directed the IOUs to incorporate cost data related to EV infrastructure upgrades for commercial customer sites in the 2020 report and extended the interim treatment for Electric Rules 15 and 16 allowances to December 31, 2019.[12] An ALJ Ruling as part of R.18-12-006 extended the interim treatment policy once again to December 31, 2021.[13] On November 5, 2019, the IOUs sent a letter to CPUC Executive Director requesting permission to delay the filing of the 2020 report from January 31, 2020 to March 31, 2020 and to adjust the content of the report. On January 6, 2020, the Administrative Law Judge (ALJ) issued a Ruling Amending the Load Research Report Deadline for 2020 and Beyond.[14] The ALJ Ruling established March 31 as the filing deadline for the 2020 report and any subsequent Electric Vehicle Load Research Reports.[15]

III. Load Research and Customer Behavior on Rates in Various Settings

A. Overview and Approach

This report provides residential and commercial EV load through December 2020 by (1) rate and (2) pilot-programs. The report reflects Commission requirements, including the Phase 2 Decision directive that the IOUs:

1. Track and quantify all new load and associated upgrade costs in a manner that allows EV load and related costs to be broken out and specifically identified. This information shall be collected and stored in an accessible format useful to the Commission.

[10] D.16-06-011, Ordering Paragraph 2.

[11] R.18-12-006, Order Instituting Rulemaking to Continue the Development of Rates and Infrastructure for Vehicle Electrification and Closing Rulemaking 13-11-007, December 19, 2018, p. 15.

[12] R.18-12-006, Assigned Commissioner's Scoping Memo and Ruling, May 2, 2019, p. 18.

[13] R.18-12-006, ALJ E-mail Ruling Extending Interim Policy on Common Facility Costs, issued on November 23, 2020.

[14] R.18-12-006, Administrative Law Judge's Ruling Amending Load Research Report Deadline for 2020 and Beyond, January 6, 2020, p.3. The ALJ Ruling approves filing the report on March 31 of the given reporting year going forward.

[15] ALJ Ruling, p. 1.

2. Evaluate how metering arrangements and rate design impact PEV charging behavior.

3. To the extent relevant, determine whether participation in demand response programs impacts EV charging behavior.

4. Determine how charging arrangements, including metering options and alternative rate schedules impact charging behavior at Multi-Dwelling Units (MDU)."[16]

This metering data provides the basis for analyzing how charging behavior is impacted by tariff rates or charging levels. Additionally, the recorded data allowed for the evaluation of metering scenarios on PEV charging behavior for customers in the following residential categories:[17]

- Single Family Home (SF)
- Multi Family Dwelling Unit (MDU)
- Net Energy Metering (NEM)

Distinctions between single metering and separate metering are shown, as well as NEM participation. The usage and demand of customers were tracked in each rate group. The goal of this structure was to determine how monthly usage varies, how rates impact peak demand and how usage varies by time-of-use rate among different groups of customers. A baseline for residential customers has been analyzed for context in the form of an average for a month during the season being examined.

To the extent possible, the IOUs provided similar information for easy comparisons. However, there are some cases where this is simply not possible due to differences in the underlying IOU data. Metrics with less than 15 customers are clearly noted and not reported without prior notice due to confidentiality concerns described in the 15/15 Rule adopted by the Commission in Decision 97-10-031 and Decision 14-05-016. All time periods are reported in 24-hour time. SCE's load profiles are reported in Pacific Standard Time while PG&E and SDG&E are provided in prevailing time. Time-of-use periods vary across the IOUs and will be explicitly defined within each IOU section.

[16] D.11-07-029, Ordering Paragraph 6.

[17] The MDU and SF categories are mutually exclusive. However, the other categories can overlap. For example, a NEM customer that is also on DR would appear in three categories.

B. PG&E's Load and Customer Behavior Data

Load and utilization across PG&E's EV-specific rates and a portion of the Transportation Electrification Programs are reported in the following sections. The study period covers the full calendar years of 2019 and 2020. PG&E's rates during the study period included residential and commercial products. The residential rates reported include PG&E's Single-Metered Rates (EV-A and EV2-A) and a Separately-Metered Rate (EV-B). However, EV-A was closed to new enrollments with the introduction of EV2-A in July 2019 and most customers were fully transitioned to the EV2-A rate by the end of 2019. The load data for single-metered residential customers in 2019 and 2020 reflects both EV-A and EV2-A customers.

PG&E launched the BEV-1 and BEV-2 rates in May 2020, for commercial customers. Load data for both rates is reported for the 2020 calendar year. Additionally, utilization and load data for light duty infrastructure installed as part of PG&E's Transportation Electrification Programs is reported for both calendar years. Principally, utilization is from charging infrastructure installed as part of the Electric Vehicle Choice Network (EVCN) program. Finally, this report also references utilization data from Evaluation Reports for each of PG&E's three Priority Review Projects (PRPs). Note that the Evaluation Reports for each PRP were drafted and filed in parallel to this report.

A note to be aware of is the impact COVID-19 and shelter-in-place orders may have had on EV driving and charging behavior throughout the 2020 calendar year. This results in some inconsistencies in load patterns when comparing 2019 with 2020 data. Ultimately, 2020 proved to be a year with unique circumstances that may have affected traditional expectations from rate price signals and time-of-use structures.

Residential PEV Rates

Single-Metered and Separately-Metered PEV Residential Rates

As of the date of this report, PG&E has two residential EV rates open to customers, one for single-metered customers (EV2-A) and another for separately-metered customers (EV-B). A previous version of the single-metered rate was closed to new customers in July 2019. The single-metered rate is a residential whole home rate that applies to both typical load and electric vehicle charging on the same meter. The separately-metered rate is designed for customers who wish to bill their vehicle charging separately and requires the installation of a separate meter to do so. Both rate plans use an un-tiered TOU rate structure. They offer on-peak, partial peak, and off-peak energy prices according to the time periods in Tables PG&E-1a and PG&E-1c. Regardless of season, or day of the week, both rates seek to encourage usage in off-peak hours. The single-metered rate includes off-peak hours from 12:00 a.m. to 3:00 p.m., and the separately-metered rate from 11:00 p.m. to 7:00 a.m. The separately-metered rate further encourages weekend usage by limiting peak periods to 3:00 p.m. to 7:00 p.m. and expanding the "off-peak" period to all other remaining hours on weekends and holidays.

Table PG&E-1a: Tariff Type and Rate ($/kWh) in 2019

Rate: EVA

Hour	Winter Weekday	Winter Weekend / Holidays	Summer Weekday	Summer Weekend / Holidays
12mn - 1am	0.13913	0.13913	0.13578	0.13578
1am - 2am	0.13913	0.13913	0.13578	0.13578
2am - 3am	0.13913	0.13913	0.13578	0.13578
3am - 4am	0.13913	0.13913	0.13578	0.13578
4am - 5am	0.13913	0.13913	0.13578	0.13578
5am - 6am	0.13913	0.13913	0.13578	0.13578
6am - 7am	0.13913	0.13913	0.13578	0.13578
7am - 8am	0.22641	0.13913	0.28917	0.13578
8am - 9am	0.22641	0.13913	0.28917	0.13578
9am - 10am	0.22641	0.13913	0.28917	0.13578
10am - 11am	0.22641	0.13913	0.28917	0.13578
11am - 12nn	0.22641	0.13913	0.28917	0.13578
12nn - 1pm	0.22641	0.13913	0.28917	0.13578
1pm - 2pm	0.22641	0.13913	0.28917	0.13578
2pm - 3pm	0.37313	0.13913	0.53476	0.13578
3pm - 4pm	0.37313	0.37313	0.53476	0.53476
4pm - 5pm	0.37313	0.37313	0.53476	0.53476
5pm - 6pm	0.37313	0.37313	0.53476	0.53476
6pm - 7pm	0.37313	0.37313	0.53476	0.53476
7pm - 8pm	0.37313	0.13913	0.53476	0.13578
8pm - 9pm	0.37313	0.13913	0.53476	0.13578
9pm - 10pm	0.22641	0.13913	0.28917	0.13578
10pm - 11pm	0.22641	0.13913	0.28917	0.13578
11pm - 12mn	0.13913	0.13913	0.13578	0.13578

Rate: EV2A

Hour	Winter All days including Holidays	Summer All days including Holidays
12mn - 1am	0.16234	0.16234
1am - 2am	0.16234	0.16234
2am - 3am	0.16234	0.16234
3am - 4am	0.16234	0.16234
4am - 5am	0.16234	0.16234
5am - 6am	0.16234	0.16234
6am - 7am	0.16234	0.16234
7am - 8am	0.16234	0.16234
8am - 9am	0.16234	0.16234
9am - 10am	0.16234	0.16234
10am - 11am	0.16234	0.16234
11am - 12nn	0.16234	0.16234
12nn - 1pm	0.16234	0.16234
1pm - 2pm	0.16234	0.16234
2pm - 3pm	0.16234	0.16234
3pm - 4pm	0.33103	0.36435
4pm - 5pm	0.34773	0.47484
5pm - 6pm	0.34773	0.47484
6pm - 7pm	0.34773	0.47484
7pm - 8pm	0.34773	0.47484
8pm - 9pm	0.34773	0.47484
9pm - 10pm	0.33103	0.36435
10pm - 11pm	0.33103	0.36435
11pm - 12mn	0.33103	0.36435

Rate: EVB

Hour	Winter Weekday	Winter Weekend / Holidays	Summer Weekday	Summer Weekend / Holidays
12mn - 1am	0.13867	0.13867	0.13535	0.13535
1am - 2am	0.13867	0.13867	0.13535	0.13535
2am - 3am	0.13867	0.13867	0.13535	0.13535
3am - 4am	0.13867	0.13867	0.13535	0.13535
4am - 5am	0.13867	0.13867	0.13535	0.13535
5am - 6am	0.13867	0.13867	0.13535	0.13535
6am - 7am	0.13867	0.13867	0.13535	0.13535
7am - 8am	0.22323	0.13867	0.28619	0.13535
8am - 9am	0.22323	0.13867	0.28619	0.13535
9am - 10am	0.22323	0.13867	0.28619	0.13535
10am - 11am	0.22323	0.13867	0.28619	0.13535
11am - 12nn	0.22323	0.13867	0.28619	0.13535
12nn - 1pm	0.22323	0.13867	0.28619	0.13535
1pm - 2pm	0.22323	0.13867	0.28619	0.13535
2pm - 3pm	0.36678	0.13867	0.52879	0.13535
3pm - 4pm	0.36678	0.36678	0.52879	0.52879
4pm - 5pm	0.36678	0.36678	0.52879	0.52879
5pm - 6pm	0.36678	0.36678	0.52879	0.52879
6pm - 7pm	0.36678	0.36678	0.52879	0.52879
7pm - 8pm	0.36678	0.13867	0.52879	0.13535
8pm - 9pm	0.36678	0.13867	0.52879	0.13535
9pm - 10pm	0.22323	0.13867	0.28619	0.13535
10pm - 11pm	0.22323	0.13867	0.28619	0.13535
11pm - 12mn	0.13867	0.13867	0.13535	0.13535

Legend:

	Winter	Summer
On		
Part		
Off		

* While the table depicts 24-hour time, there is a daylight saving time adjustment as described in the tariff.

** Rates effective through December 31, 2019. For details see Electric Schedule EV, Residential Time-of-Use Service for Plug-in Electric Vehicle Customers, retrieved from https://www.pge.com/tariffs/assets/pdf/tariffbook/ELEC_SCHEDS_EV%20(Sch).pdf

These rates change seasonally, generally rising in summer and dropping in winter. Tables PG&E-1b and PG&E-1d depict price ratios for the TOU periods by season to illustrate this seasonal difference.

Table PG&E-1b: Price Ratios for 2019

	EV-A		EV2-A		EV-B	
Season	Between Off-Peak and Partial Peak	Between Off-Peak and Peak	Between Off-Peak and Partial Peak	Between Off-Peak and Peak	Between Off-Peak and Partial Peak	Between Off-Peak and Peak
Winter	0.61	0.37	0.62	0.38	0.49	0.47
Summer	0.47	0.25	0.47	0.26	0.45	0.34

Table PG&E-1c: Tariff Type and Rate ($/kWh) in 2020

Rate: EVA

Hour	Winter Weekday	Winter Weekend / Holidays	Summer Weekday	Summer Weekend / Holidays
12mn - 1am	0.15022	0.15022	0.14686	0.14686
1am - 2am	0.15022	0.15022	0.14686	0.14686
2am - 3am	0.15022	0.15022	0.14686	0.14686
3am - 4am	0.15022	0.15022	0.14686	0.14686
4am - 5am	0.15022	0.15022	0.14686	0.14686
5am - 6am	0.15022	0.15022	0.14686	0.14686
6am - 7am	0.15022	0.15022	0.14686	0.14686
7am - 8am	0.24004	0.15022	0.30206	0.14686
8am - 9am	0.24004	0.15022	0.30206	0.14686
9am - 10am	0.24004	0.15022	0.30206	0.14686
10am - 11am	0.24004	0.15022	0.30206	0.14686
11am - 12nn	0.24004	0.15022	0.30206	0.14686
12nn - 1pm	0.24004	0.15022	0.30206	0.14686
1pm - 2pm	0.24004	0.15022	0.30206	0.14686
2pm - 3pm	0.38938	0.15022	0.54919	0.14686
3pm - 4pm	0.38938	0.38938	0.54919	0.54919
4pm - 5pm	0.38938	0.38938	0.54919	0.54919
5pm - 6pm	0.38938	0.38938	0.54919	0.54919
6pm - 7pm	0.38938	0.38938	0.54919	0.54919
7pm - 8pm	0.38938	0.15022	0.54919	0.14686
8pm - 9pm	0.38938	0.15022	0.54919	0.14686
9pm - 10pm	0.24004	0.15022	0.30206	0.14686
10pm - 11pm	0.24004	0.15022	0.30206	0.14686
11pm - 12mn	0.15022	0.15022	0.14686	0.14686

Rate: EV2A

Hour	Winter All days including Holidays	Summer All days including Holidays
12mn - 1am	0.16675	0.16675
1am - 2am	0.16675	0.16675
2am - 3am	0.16675	0.16675
3am - 4am	0.16675	0.16675
4am - 5am	0.16675	0.16675
5am - 6am	0.16675	0.16675
6am - 7am	0.16675	0.16675
7am - 8am	0.16675	0.16675
8am - 9am	0.16675	0.16675
9am - 10am	0.16675	0.16675
10am - 11am	0.16675	0.16675
11am - 12nn	0.16675	0.16675
12nn - 1pm	0.16675	0.16675
1pm - 2pm	0.16675	0.16675
2pm - 3pm	0.16675	0.16675
3pm - 4pm	0.33544	0.36876
4pm - 5pm	0.35214	0.47925
5pm - 6pm	0.35214	0.47925
6pm - 7pm	0.35214	0.47925
7pm - 8pm	0.35214	0.47925
8pm - 9pm	0.35214	0.47925
9pm - 10pm	0.33544	0.36876
10pm - 11pm	0.33544	0.36876
11pm - 12mn	0.33544	0.36876

Rate: EVB

Hour	Winter Weekday	Winter Weekend / Holidays	Summer Weekday	Summer Weekend / Holidays
12mn - 1am	0.14976	0.14976	0.14643	0.14643
1am - 2am	0.14976	0.14976	0.14643	0.14643
2am - 3am	0.14976	0.14976	0.14643	0.14643
3am - 4am	0.14976	0.14976	0.14643	0.14643
4am - 5am	0.14976	0.14976	0.14643	0.14643
5am - 6am	0.14976	0.14976	0.14643	0.14643
6am - 7am	0.14976	0.14976	0.14643	0.14643
7am - 8am	0.23683	0.14976	0.29905	0.14643
8am - 9am	0.23683	0.14976	0.29905	0.14643
9am - 10am	0.23683	0.14976	0.29905	0.14643
10am - 11am	0.23683	0.14976	0.29905	0.14643
11am - 12nn	0.23683	0.14976	0.29905	0.14643
12nn - 1pm	0.23683	0.14976	0.29905	0.14643
1pm - 2pm	0.23683	0.14976	0.29905	0.14643
2pm - 3pm	0.38296	0.14976	0.54316	0.14643
3pm - 4pm	0.38296	0.38296	0.54316	0.54316
4pm - 5pm	0.38296	0.38296	0.54316	0.54316
5pm - 6pm	0.38296	0.38296	0.54316	0.54316
6pm - 7pm	0.38296	0.38296	0.54316	0.54316
7pm - 8pm	0.38296	0.14976	0.54316	0.14643
8pm - 9pm	0.38296	0.14976	0.54316	0.14643
9pm - 10pm	0.23683	0.14976	0.29905	0.14643
10pm - 11pm	0.23683	0.14976	0.29905	0.14643
11pm - 12mn	0.14976	0.14976	0.14643	0.14643

Legend:

	Winter	Summer
On		
Part		
Off		

*While the table depicts 24-hour time, there is a daylight saving time adjustment as described in the tariff.

** Rates effective through December 31, 2020. For details see Electric Schedule EV, Residential Time-of-Use Service for Plug-in Electric Vehicle Customers, retrieved from https://www.pge.com/tariffs/assets/pdf/tariffbook/ELEC_SCHEDS_EV%20(Sch).pdf

Table PG&E-1d: Price Ratios for 2020

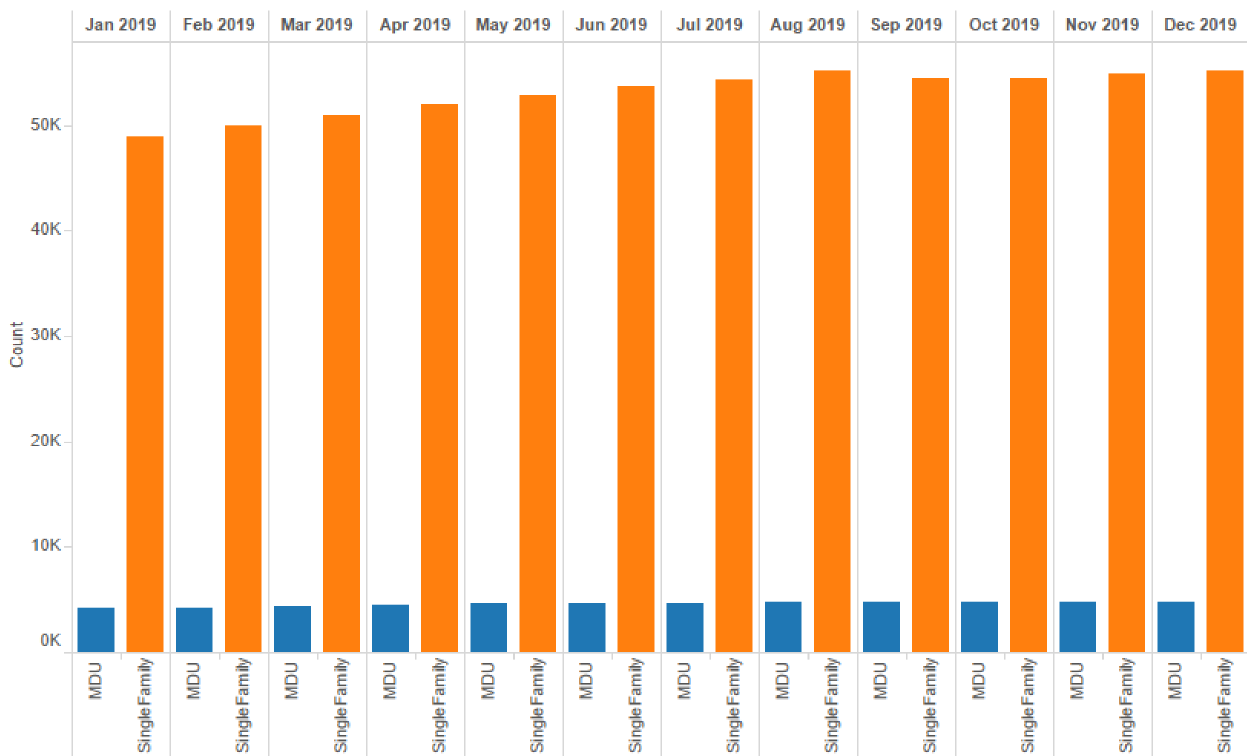
	EV-A		EV2-A		EV-B	
Season	Between Off-Peak and Partial Peak	Between Off-Peak and Peak	Between Off-Peak and Partial Peak	Between Off-Peak and Peak	Between Off-Peak and Partial Peak	Between Off-Peak and Peak
Winter	0.63	0.39	0.63	0.39	0.50	0.47
Summer	0.49	0.27	0.49	0.27	0.45	0.35

Single-Metered Rate Growth

Participation in the single-metered PEV rate showed a small, but steady increase during 2019 and 2020, the duration of the study period, as seen in Charts PG&E-1a and 1b. Participation in the separately-metered PEV rate remained relatively steady among MDU[18] customers and had a small, but steady increase among SF home customers during 2019 through 2020. It is important to note that not all EV customers have adopted PEV rates.[19] Of the customers on PEV rates, the majority are on the single-metered rate.

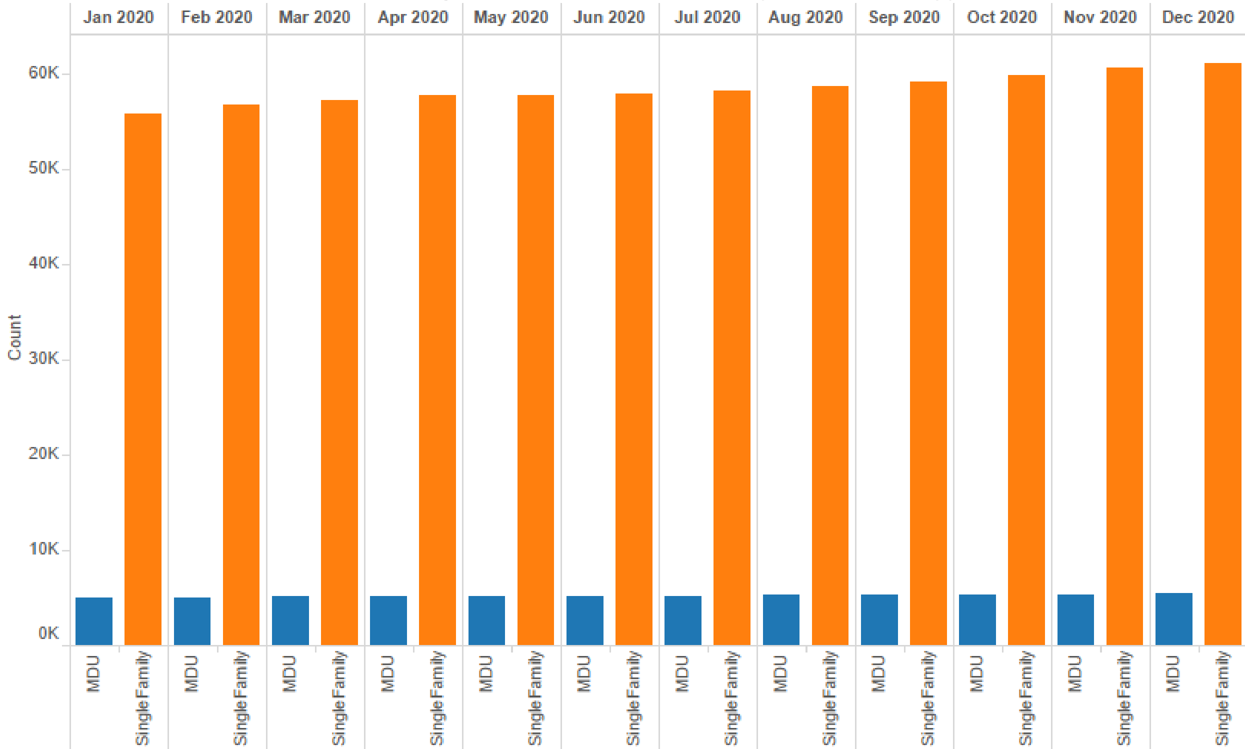
All Single-Metered Customers: Charts PG&E-1a and 1b, below, display the total customers on the single-metered PEV rate in 2019 and 2020, respectively. During the study period, there was a steady increase in single-metered rate enrollment overall, primarily in the SF subcategories. The number of accounts in the single-metered group as a whole increased by 13% between January and December in 2019 and by 9.6% in 2020. Please note the different scale of the y-axes.

Chart PG&E-1a: Single-Metered Accounts by Customer Type (2019)



[18] Multi-dwelling units (MDUs) are defined as a residential unit with a shared wall (e.g. condo or townhouse) and are distinct from Multi-unit dwellings (MUDs) (e.g. apartment buildings) which are considered non-residential.
[19] The load research figures in this report only represent the number of PG&E PEV customers on PEV rates, not all PEV customers.

Chart PG&E-1b: Single-Metered Accounts by Customer Type (2020)



NEM Single-Metered Customers: Net Energy Metering (NEM) customers on the PEV rates are an important group to consider. Of all the PG&E customers who were on the single-metered rate, up to 34% were also on NEM at any given time during the two-year study period. Virtually all dual PEV Rate/NEM customers were on the single-metered rate (see Tables PG&E-2a and 2b).

The fact that NEM customers with PEVs predominately use the single-metered rate presents a load research challenge. The presence of onsite distributed generation (DG) alongside a PEV behind these customers' meters indicates that their utility energy usage data does not reflect their gross consumption. This is because the DG will have offset some portion of consumption. However, without additional metering of the DG, it is not feasible to isolate the effect PEV ownership has on usage patterns for this group using utility metering data alone.[20]

Table PG&E-2a: Single-Metered NEM Program Enrollment by Customer Type (2019)

Year	Month	Number of Single-Metered NEM Enrollments	NEM % of Single-Metered	NEM % of SF Single-Metered	NEM % of MDU Single-Metered
2019	Jan	13,820	26%	24%	2%
2019	Feb	13,019	27%	24%	2%
2019	Mar	14,735	27%	25%	2%

[20]While there are numerous other demographic and behavioral attributes of this early PEV adopter group that affect usage, there was insufficient data or resources to isolate and identify their contribution to load shapes.

2019	Apr	15,124	27%	25%	2%
2019	May	15,633	27%	25%	2%
2019	Jun	16,091	28%	26%	2%
2019	Jul	16,701	28%	26%	2%
2019	Aug	16,338	29%	26%	2%
2019	Sep	17,543	29%	27%	2%
2019	Oct	17,899	30%	28%	2%
2019	Nov	15,683	31%	28%	2%
2019	Dec	18,581	31%	29%	2%

* Numbers may not add up to 100% due to rounding

Table PG&E-2b: Single-Metered NEM Program Enrollment by Customer Type (2020)

Year	Month	Number of Single-metered NEM Enrollments	NEM % of Single-metered	NEM % of SF Single-metered	NEM % of MDU Single-metered
2020	Jan	18,972	31%	29%	2%
2020	Feb	17,504	31%	29%	2%
2020	Mar	19,759	32%	29%	2%
2020	Apr	20,067	32%	30%	2%
2020	May	19,250	32%	30%	2%
2020	Jun	20,444	32%	30%	2%
2020	Jul	20,637	33%	30%	2%
2020	Aug	20,836	33%	31%	2%
2020	Sep	21,090	33%	31%	2%
2020	Oct	20,527	33%	31%	2%
2020	Nov	20,817	33%	32%	2%
2020	Dec	22,317	34%	32%	2%

* Numbers may not add up to 100% due to rounding

Separately-Metered Rate Growth

All Separately-metered Customers: The separately-metered PEV rate remains a less popular option for PEV rate customers than the single-metered PEV rate. As shown in Charts PG&E-2a and 2b, compared to the single-metered rate, there was lower participation and only a small increase in enrollment between January and December 2019 (1.6%) with a slight decline in 2020 (-2.5%). While the installation of a separate meter for EV charging could be financially challenging for some customers, PG&E is exploring strategies to make the separately-metered rate more accessible to all customers.

Chart PG&E-2a: Separately-Metered Accounts by Customer Type (2019)

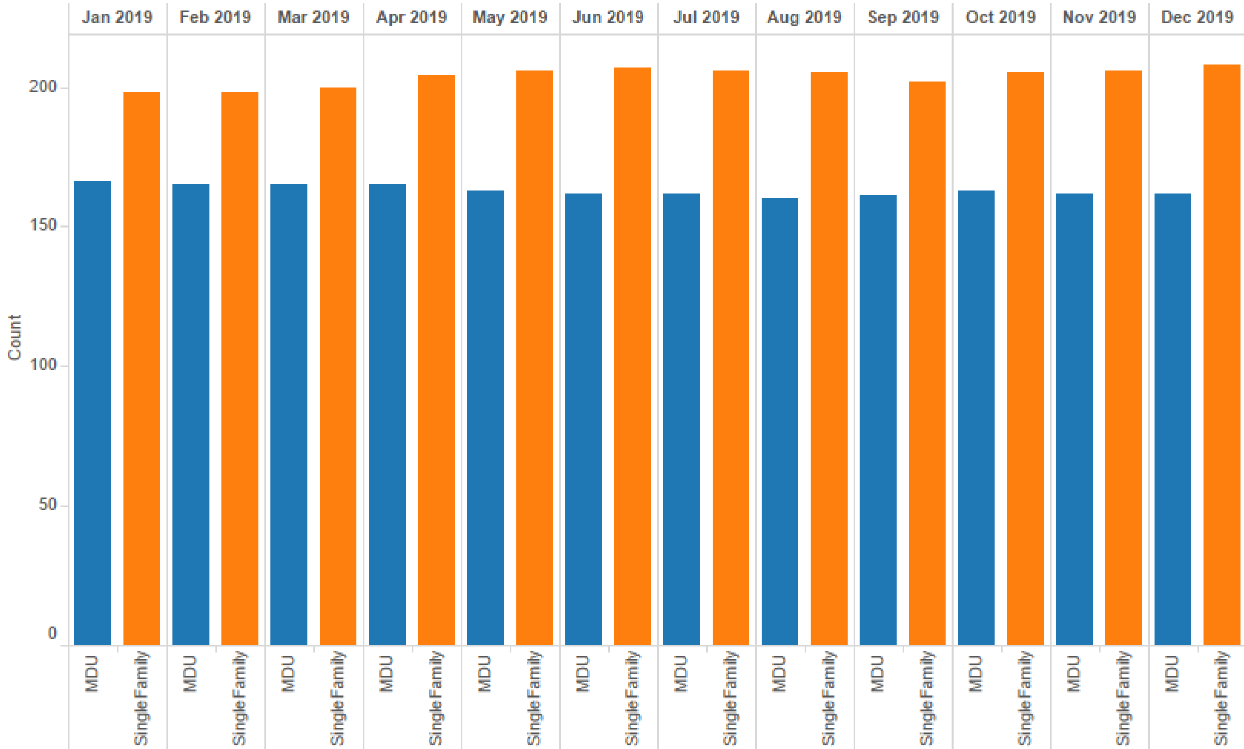
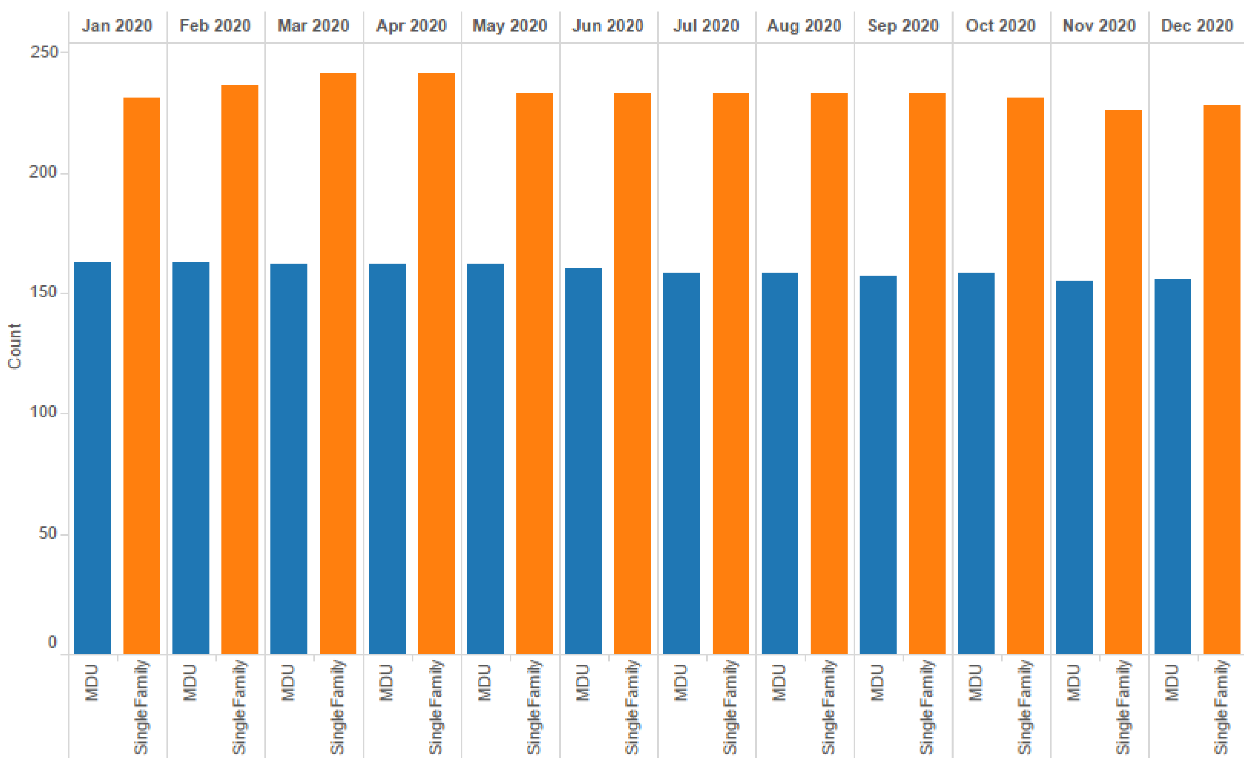


Chart PG&E-2b: Separately-Metered Accounts by Customer Type (2020)



NEM Separately-Metered Customers: There are only a small number of PEV rate customers on the separately-metered PEV rate and enrolled in NEM in 2019 and 2020 and therefore the specific enrollment numbers cannot be shared publicly. As shown in Tables PG&E-3a and 3b, the number of separately-metered customers enrolled in NEM remained relatively flat during the study period. The single-metered PEV rate continues to be the more popular option for PEV customers wishing to offset their charging with DG.

Table PG&E-3a: Separately-Metered NEM Program Enrollment by Customer Type (2019)

Year	Month	Number of Separately-metered NEM Enrollments	NEM % of Separately-metered	NEM % of SF Separately-metered	NEM % of MDU Separately-metered
2019	Jan	<100	6%	4%	2%
2019	Feb	<100	6%	4%	2%
2019	Mar	<100	6%	4%	2%
2019	Apr	<100	6%	4%	2%
2019	May	<100	6%	4%	2%
2019	Jun	<100	6%	4%	2%
2019	Jul	<100	6%	4%	2%
2019	Aug	<100	7%	4%	2%
2019	Sep	<100	6%	4%	2%
2019	Oct	<100	7%	5%	2%
2019	Nov	<100	7%	5%	2%
2019	Dec	<100	7%	5%	2%

* Numbers may not add up to 100% due to rounding

Table PG&E-3b: Separately-Metered NEM Program Enrollment by Customer Type (2020)

Year	Month	Number of Separately-metered NEM Enrollments	NEM % of Separately-metered	NEM % of SF Separately-metered	NEM % of MDU Separately-metered
2020	Jan	<100	7%	5%	2%
2020	Feb	<100	7%	4%	3%
2020	Mar	<100	7%	4%	2%
2020	Apr	<100	7%	4%	2%
2020	May	<100	7%	5%	2%
2020	Jun	<100	7%	5%	2%
2020	Jul	<100	7%	5%	2%
2020	Aug	<100	7%	4%	2%
2020	Sep	<100	7%	4%	2%
2020	Oct	<100	6%	4%	2%
2020	Nov	<100	7%	5%	2%
2020	Dec	<100	7%	5%	2%

* Numbers may not add up to 100% due to rounding

Notes of Caution Regarding Reliance upon Load Research Data

The reader should take careful note of the following issues that make the load research data ill-suited for drawing conclusions for policymaking at this time.

- While PEV ownership has increased, it is still largely comprised of early adopters who are likely to be materially different than future PEV owners. These differences could include, but are not limited to, income, commuting patterns, pre-PEV ownership usage habits, NEM penetration, altruistic tendencies, and willingness/ability to adopt usage patterns beneficial to grid stability.
- The types of PEVs available in the market evolved through the year, suggesting that the types of PEVs owned by PEV rate customers would have changed during that same time frame. New vehicles and charging requirements may lead to changes in charging profiles in the future (i.e., differing charging demands and durations).
- The customer counts were relatively small in all cases. This is particularly true for separately-metered PEV rate data derived from PG&E's load research sample. The mix of customers being evaluated changed over time due to customers joining or leaving the single-metered or separately-metered PEV rates. The single-metered rate also transitioned from the EV-A rate, which closed to new enrollments in July of 2019, to the new EV2-A rate, which opened at the same time. Additionally, effective July 2019, all customers on an EV rate are subject to eligibility criteria based on usage. Customers who exceed 800% of their cumulative baseline after 12-months of usage are removed from the rate and placed on an alternative TOU rate.
- While PEV charging for the single-metered PEV rate may be fairly obvious if it takes place during off-peak rate periods when there is low electric consumption from other sources, the lack of on-site survey or end use data to help disaggregate other loads from PEV charging prevents the identification of PEV charging in other periods (particularly partial-peak) where multiple significant loads are likely present.

Therefore, while the data collected are illustrative of the behaviors of early adopters based on the types of vehicles that are currently available in the market, one cannot conclude that these behavior patterns will hold as PEV technology matures, as charging technology and charging behaviors evolve, and as PEVs achieve greater market adoption beyond the early adopter phase. PG&E will continue to collect and report load data from residential EV rate customers via this report, but specific learnings to influence policy should be obtained via an appropriately funded and carefully designed study that controls for the above issues.

Average Monthly Usage for PEV Rate Customers

Keeping in mind the above cautions about the data collected, Charts PG&E-3a and PG&E-4a display the average monthly usage for single-metered customers with NEM during 2019 and 2020, which means that the average monthly usage of these categories is net of behind-the-meter generation. Charts PG&E-3b and PG&E-4b display the average monthly usage for each single-metered category without NEM. Please note the different scale of the y-axes on each chart.

Chart PG&E-3a: Single-Metered Average Monthly Usage (kWh) by Customer Type With NEM (2019)

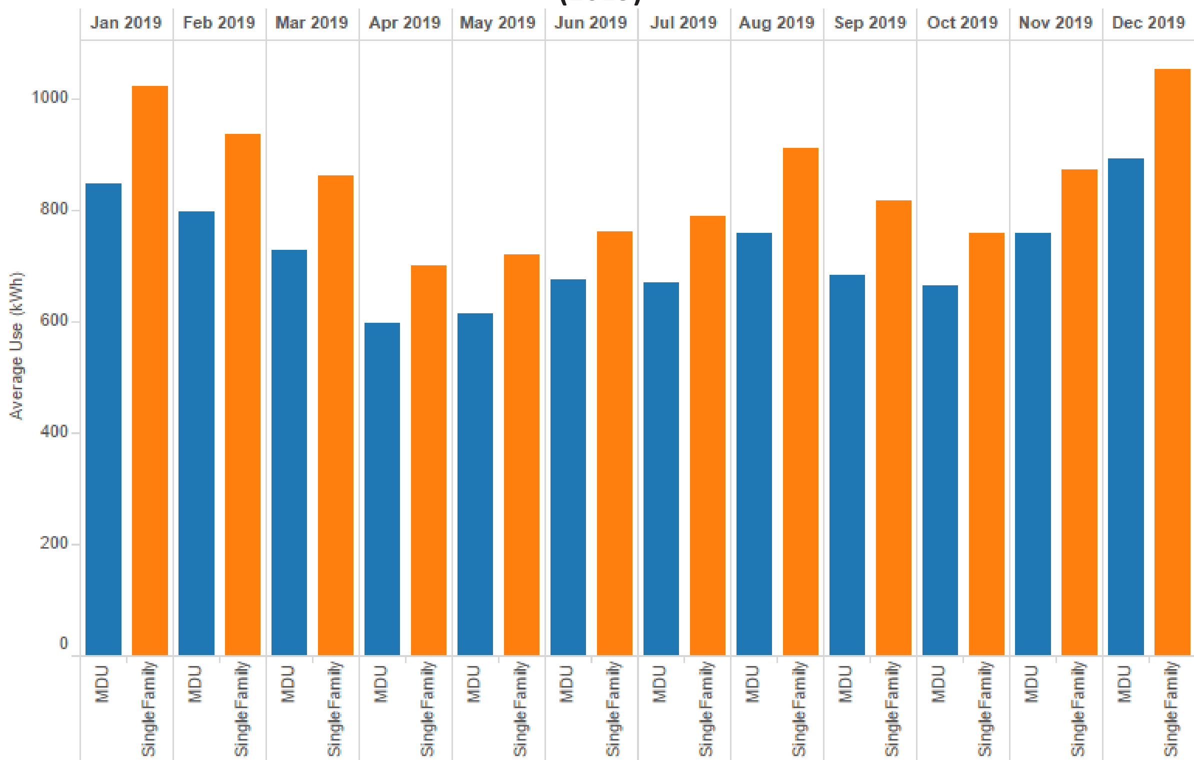


Chart PG&E-3b: Single-Metered Average Monthly Usage (kWh) by Customer Type Without NEM (2019)

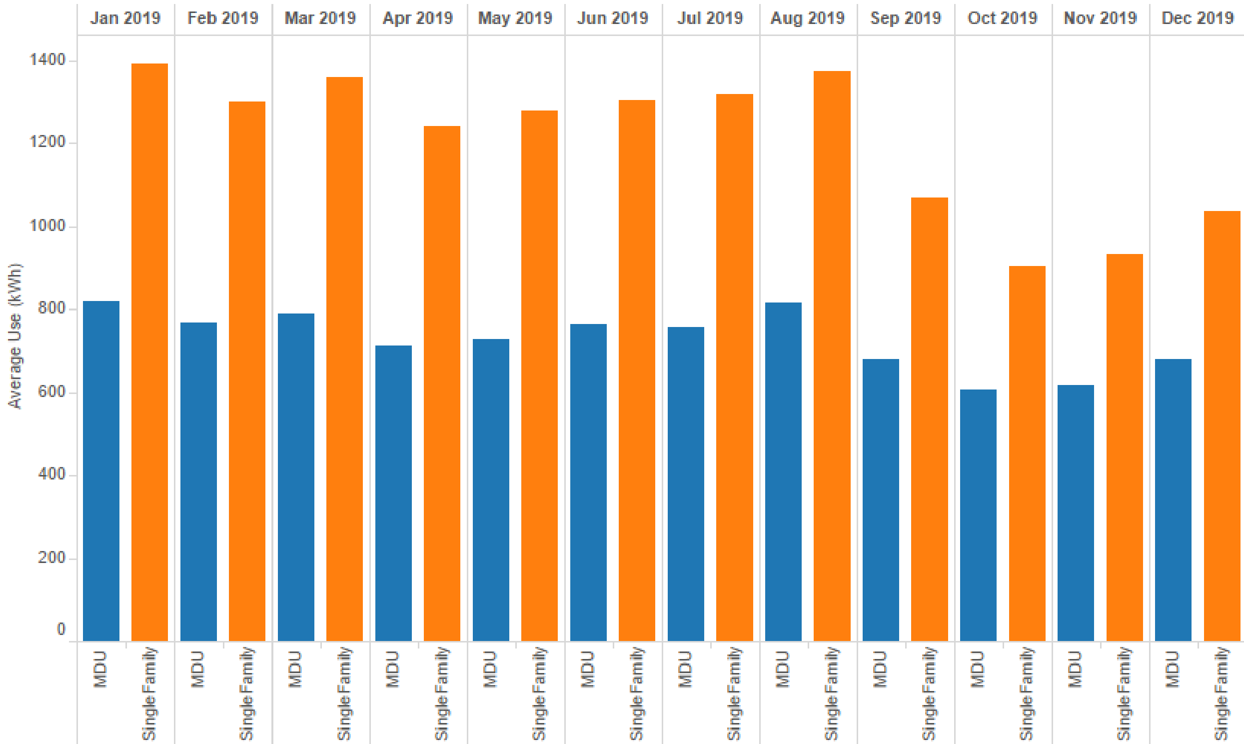


Chart PG&E-4a: Single-Metered Average Monthly Usage (kWh) by Customer Type With NEM (2020)

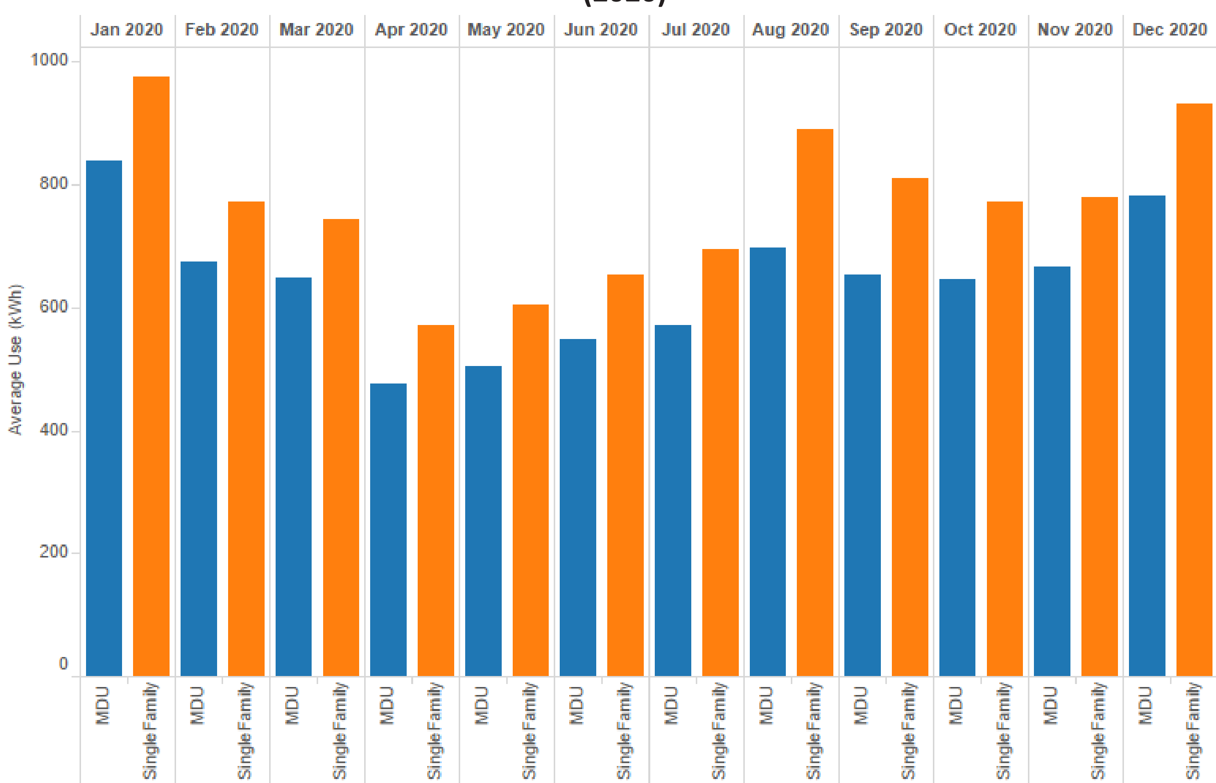
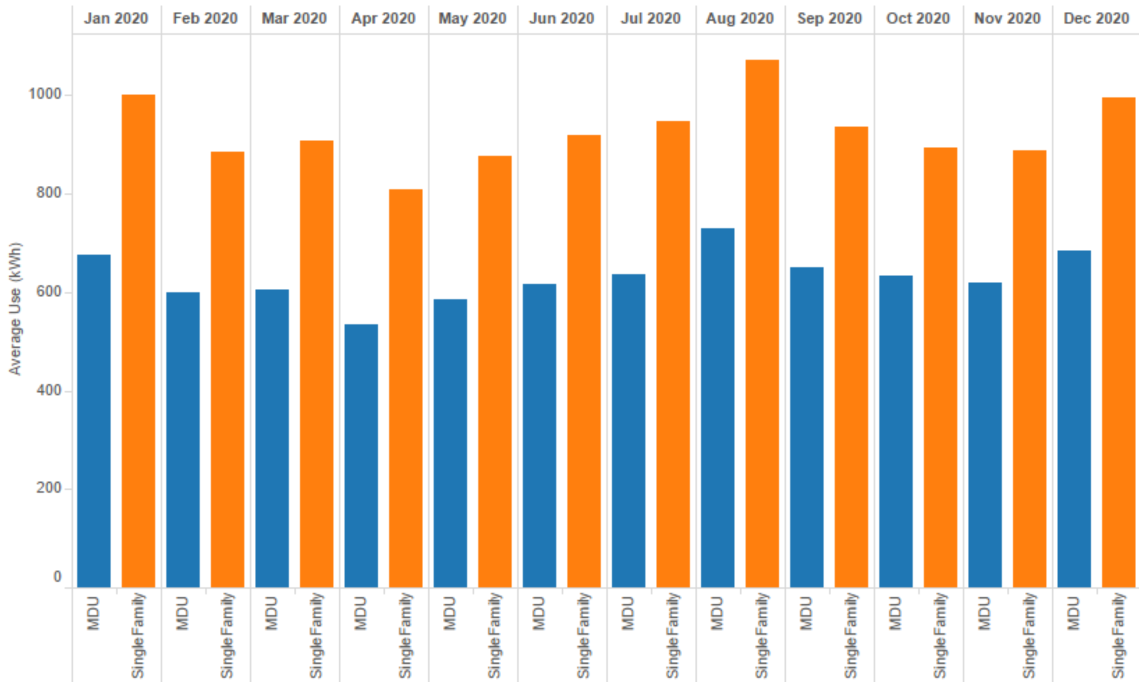


Chart PG&E-4b: Single-Metered Average Monthly Usage (kWh) by Customer Type Without NEM (2020)



A comparison of customers with NEM and customers without for both 2019 and 2020 reveals an unsurprising result for both sectors: absent the NEM accounts, usage is relatively flatter for PEV rate customers throughout the study period. This result demonstrates that offsetting consumption with behind-the-meter generation obfuscates researchers' ability to parse PEV load from other site loads for NEM customers using their consumption data alone. The slight fluctuation during 2020 during the spring and winter could be related to shelter-in-place orders affecting commutes and overall travel. The slight drop in average usage at the end of 2019 for customers without NEM may be a reflection of the relatively mild weather and PSPS events that were called during that time.

In Charts PG&E-5a and PG&E-5b, NEM customers are not segregated among separately-metered customers because the average use (kWh) cannot be shared publicly due to the low penetration among separately-metered customers.

Chart PG&E-5a: Separately-Metered Average Monthly Usage (kWh) by Customer Type (2019)

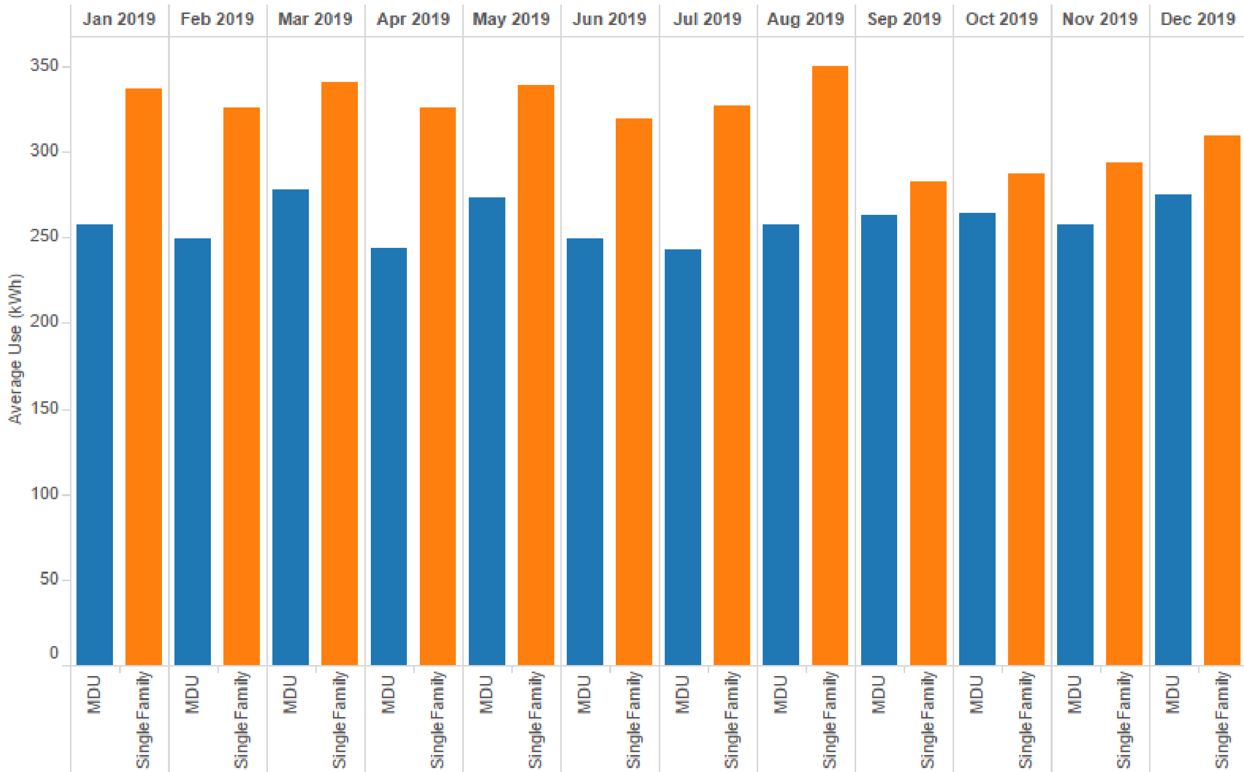
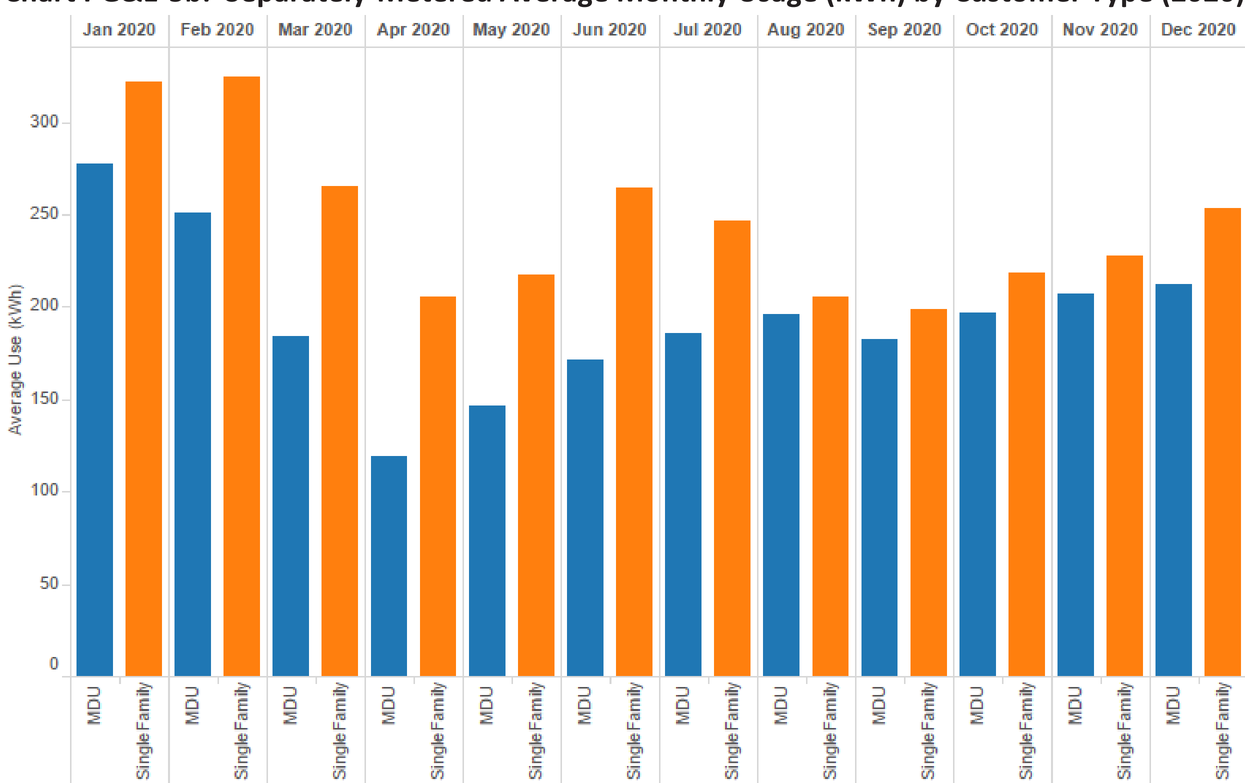


Chart PG&E-5b: Separately-Metered Average Monthly Usage (kWh) by Customer Type (2020)



Charts PG&E-5a and PG&E-5b show that, absent other loads on the meter, researchers can better observe that PEV rate customers' total charging amount remains relatively consistent over time. The results in Chart PG&E-5a are relatively flat for the 2019 period, while Chart PG&E-5b shows some relative fluctuation in 2020. This is likely a result of shelter-in-place orders that started in the spring of 2020. The slight decline in separately-metered customers in the second half of 2020 could also have impacted overall utilization during those months.

Average Usage during Time of Use Periods

TOU PEV rates are designed to discourage charging during peak hours and instead encourage charging during off-peak hours when the grid is less stressed and generation costs are lower. For single-metered and separately-metered customers, the time of use periods in 2019 are defined in Table PG&E-1a, and time of use periods in 2020 are defined in Table PG&E-1c.

One useful way to determine whether the TOU PEV rates are achieving their goal of avoiding peak PEV charging is to measure the distribution of charging in the various time periods. Given that NEM customers have a very unique usage profile, they are segregated from all other single-metered customer groups in Tables PG&E-4a-6b. [21] Note that for 2020 comparisons, single-metered and separately-metered customers are independently compared to the general population per their respective TOU schedules.

1. Tables PG&E-4a and PG&E-4b show the share of peak usage by sector for single-metered and separately-metered customers with and without NEM and compares it to the peak usage of PG&E's entire residential population. In 2019, customers on the single-metered PEV rate with no NEM used energy an average of 8% less during the peak period than the average PG&E residential customer, while those with NEM used energy 12% less during the peak period. Separately-metered customers with no NEM used energy an average of 22% less during the peak period than the entire residential population, while their NEM counterparts used energy 11% less during that time. In 2020, customers on the single-metered PEV rate without NEM experienced almost the same share of demand during the peak period than the average PG&E residential customer, while those with NEM experienced a 7% higher share of demand than the residential population. This could be a result of shelter-in-place orders requiring a large fraction of the workforce to work from home and causing an increase in home utilization during, traditionally, off-peak hours for the general population. In contrast, non-NEM separately-metered customers used an average of 21% less energy during the peak period than the entire residential population, while their NEM counterparts used 9% less. As previously noted, the small customer population of NEM customers on EV-B detracts from the meaningfulness of results produced by its data. Because the goal of PEV rates is to encourage

[21] For the total residential population data, January to December 2019 data was used to compare to the 2019 PEV data and was also used as a proxy for 2020 PEV data due to the fact that 2020 total residential data is not available until July 2021.

customers to charge their vehicles during off-peak hours, the fact that PEV rate customers' peak period usage – with the exception of single-metered NEM customers in 2020 – is reasonably below that of all residential customers indicates that the PEV TOU rates are achieving this goal among this group of early PEV adopters.

2. Table PG&E-5a and PG&E-5b show the off-peak usage by sector for customers on both rates, with and without NEM, and compares it to the off-peak usage of PG&E's entire residential population. Consistent with performance expectations for customers on EV rates, during 2019, non-NEM customers on the single-metered PEV rate used an average of 14% more energy than the average PG&E residential customer, while their NEM counterparts used 32% more energy. Non-NEM separately-metered customers used an average of 42% more energy than the residential population, while NEM customers on the same rate used 32% more. In 2020, non-NEM customers on the single-metered PEV rate experienced almost the same share of demand during the off-peak period than the average PG&E residential customer while those with NEM experienced a 10% lower share of demand than the residential population. As noted previously, this could be a result of shelter-in-place orders. In contrast, non-NEM separately-metered customers used an average of 39% more energy than the residential population, while NEM customers on the same rate used 28% more. Consequently– except for single-metered NEM customers in 2020 – all groups met the off-peak performance expectations for their EV TOU rate by consuming more energy during this period than non-PEV customers.
3. Tables PG&E-6a and PG&E-6b show the share of partial peak usage by sector for customers on both rates, with and without NEM, and compares it to the partial peak usage of PG&E's entire residential population. During 2019, non-NEM single-metered customers used an average of 6% less energy than the average PG&E residential customer during partial peak periods, while NEM customers on the same rate used 19% less. Non-NEM separately-metered customers used an average of 20% less energy than the residential population during partial peak periods, while their NEM counterparts used 22% less. In 2020, non-NEM customers on the single-metered PEV rate, similarly, experienced almost the same share of demand during the partial-peak period than the average PG&E residential customer while those with NEM experienced a 3% higher share of demand than the residential population. As noted previously, this could be a result of shelter-in-place orders. In contrast, non-NEM separately-metered customers used an average of 18% less energy than the residential population during partial peak periods, while their NEM counterparts used 20% less. With the exception of single-metered NEM customers, these groups met the performance expectations for their EV TOU rate by consuming less energy during the partial peak period than non-PEV customers.

Collectively, Tables PG&E-4a – PG&E-6b show that customers on both rates are shifting their usage from peak hours to off-peak hours compared to non-PEV rate customers. Specifically, non-NEM separately-metered customers are completing, on average, over 80% of their charging during the off-peak period and less than 10% during the peak period. This suggests that customers on the PEV rates are responding effectively to their rates' price signals and charging during the off-peak periods.

Table PG&E-4a: Share of On-Peak Usage by Tariff and Customer Type (2019)

			Single-Metered				Separately-Metered			
Year	Season	Total Residential Population*	*Single Fam. no NEM*	*MDU no NEM*	**Total no NEM**	**Total with NEM**	*Single Fam. No NEM*	*MDU no NEM*	**Total no NEM**	**Total with NEM**
2019	Summer	32%	*22%*	*22%*	22%	14%	*8%*	*7%*	8%	19%
2019	Winter	28%	*21%*	*21%*	21%	21%	*8%*	*8%*	8%	18%
	Max	32%	*22%*	*22%*	22%	21%	*8%*	*8%*	8%	19%
	Avg	30%	*22%*	*21%*	22%	18%	*8%*	*8%*	8%	19%

*Load data used for the analysis are from Jan 2019 to December 2019. (See footnote 20)

Table PG&E-4b: Share of On-Peak Usage by Tariff and Customer Type (2020)

		Single-Metered					Separately-Metered				
Year	Season	Total Residential Population*	*Single Fam. no NEM*	*MDU no NEM*	**Total no NEM**	**Total with NEM**	Total Residential Population**	*Single Fam. No NEM*	*MDU no NEM*	**Total no NEM**	**Total with NEM**
2020	Summer	24%	24%	23%	24%	32%	32%	10%	8%	9%	24%
2020	Winter	23%	21%	21%	21%	29%	28%	10%	9%	10%	21%
	Max	24%	24%	23%	24%	32%	32%	10%	9%	10%	24%
	Avg	23%	23%	22%	23%	30%	30%	10%	8%	9%	22%

*Load data used for the analysis are from Jan 2019 to December 2019. (See footnote 20)
**General Population reflects usage during TOU schedule for each rate.

Table PG&E-5a: Share of Off-Peak Usage by Tariff and Customer Type (2019)

			Single-Metered				Separately-Metered			
Year	Season	Total Residential Population*	*Single Fam. no NEM*	*MDU no NEM*	**Total no NEM**	**Total with NEM**	*Single Fam. No NEM*	*MDU no NEM*	**Total no NEM**	**Total with NEM**
2019	Summer	39%	55%	57%	55%	79%	85%	85%	85%	76%
2019	Winter	44%	56%	58%	56%	68%	83%	84%	83%	75%
	Max	44%	56%	58%	56%	79%	85%	85%	85%	76%
	Avg	42%	56%	57%	56%	74%	84%	84%	84%	76%

*Load data used for the analysis are from Jan 2019 to December 2019. (See footnote 20)

Table PG&E-5b: Share of Off-Peak Usage by Tariff and Customer Type (2020)

		Single-Metered					Separately-Metered				
Year	Season	Total Residential Population*	*Single Fam. no NEM*	*MDU no NEM*	**Total no NEM**	**Total with NEM**	Total Residential Population**	*Single Fam. No NEM*	*MDU no NEM*	**Total no NEM**	**Total with NEM**
2020	Summer	58%	59%	60%	59%	46%	39%	80%	85%	82%	68%
2020	Winter	60%	63%	63%	63%	53%	44%	78%	83%	80%	71%
	Max	60%	63%	63%	63%	53%	44%	80%	85%	82%	71%
	Avg	59%	61%	61%	61%	49%	42%	79%	84%	81%	70%

*Load data used for the analysis are from Jan 2019 to December 2019. (See footnote 20)
**General Population reflects usage during TOU schedule for each rate.

Table PG&E-6a: Share of Partial-Peak Usage by Tariff and Customer Type (2019)

			Single-Metered				Separately-Metered			
Year	Season	Total Residential Population*	*Single Fam. no NEM*	*MDU no NEM*	**Total no NEM**	**Total with NEM**	*Single Fam. No NEM*	*MDU no NEM*	**Total no NEM**	**Total with NEM**
2019	Summer	29%	22%	21%	22%	7%	8%	7%	8%	5%
2019	Winter	28%	23%	21%	23%	10%	9%	8%	9%	7%
	Max	29%	23%	21%	23%	10%	9%	8%	9%	7%
	Avg	28%	23%	21%	22%	9%	8%	8%	8%	6%

*Load data used for the analysis are from Jan 2019 to December 2019. (See footnote 20)

Table PG&E-6b: Share of Partial-Peak Usage by Tariff and Customer Type (2020)

		Single-Metered					Separately-Metered				
Year	Season	Total Residential Population*	*Single Fam. no NEM*	*MDU no NEM*	**Total no NEM**	**Total with NEM**	Total Residential Population**	*Single Fam. No NEM*	*MDU no NEM*	**Total no NEM**	**Total with NEM**
2020	Summer	18%	17%	17%	17%	23%	29%	10%	7%	9%	7%
2020	Winter	17%	16%	16%	16%	19%	28%	12%	9%	11%	8%
	Max	18%	17%	17%	17%	23%	29%	12%	9%	11%	8%
	Avg	18%	17%	17%	17%	21%	28%	11%	8%	10%	8%

*Load data used for the analysis are from Jan 2019 to December 2019. (See footnote 20)
**General Population reflects usage during TOU schedule for each rate.

Average Load Profiles for PEV Rates

Depicted below in Charts PG&E-7a and 7b are the average daily load profiles for the single-metered and separately-metered rate groups for each sector during 2019 and 2020. In 2019, the load profiles demonstrate that for all rates and sectors, high off-peak usage corresponds to the PEV rate price signals, i.e., customers are largely responding to the price signal and charging during off-peak hours (11:00 p.m. to 7:00 a.m. with a bulk of the load occurring from 11:00 p.m. to 4:00 a.m.). As referenced in Table PG&E-1a and 1c, new TOU periods were introduced by the new single-metered rate – EV2-A – in July 2019 that expanded off-peak hours from 12:00 a.m. to 3:00 p.m., peak hours from 4:00 p.m. to 9:00 p.m., and partial-peak for the remaining hours. The average load profile in 2020 shown in Chart PG&E-6b reflects average load with a majority of customers transitioned to the new single-metered rate's TOU structure. The load profile during 2020 shows a spike in demand at midnight with a second smaller spike during the peak-hour period 6:00 p.m. to 10 p.m. Average kW demand at midnight peaks for single family customers is also lower in 2020 compared to 2019. This could be a result of the PEV rate eligibility criteria that went into effect in July of 2019 which removes high-use customers who exceed 800% of baseline off the rate and onto a non-PEV rate information. Based on the implementation date of this new criteria and the availability of baseline information, most high usage customers were removed from the EV-A rate in late 2019 and June 2020. Another variable may be reduced commuting or automobile travel due to shelter-in-place orders. The response to price signals is more clearly depicted in the data from the separately-metered customers (Chart PG&E-7a and Chart PG&E-7b) where the majority of the usage occurs during off-peak hours for both 2019 and 2020.

Chart PG&E-6a: Average Load Profile for SF and MDU Single-Metered by Weekday and Weekend (2019)

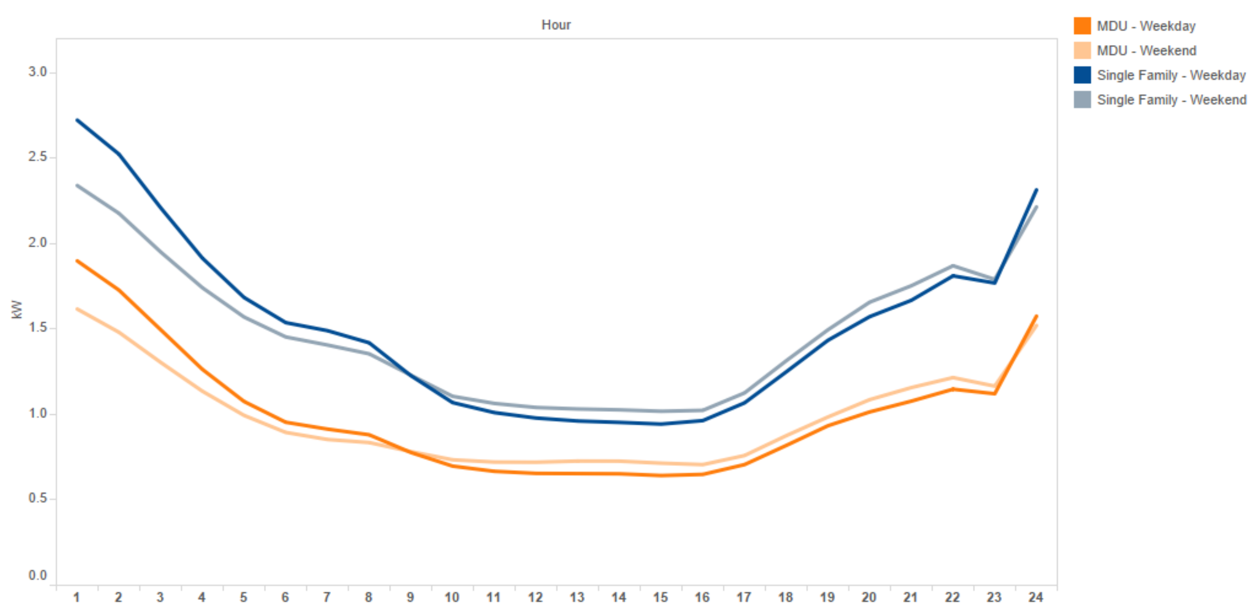


Chart PG&E-6b: Average Load Profile for SF and MDU Single-Metered by Weekday and Weekend (2020)

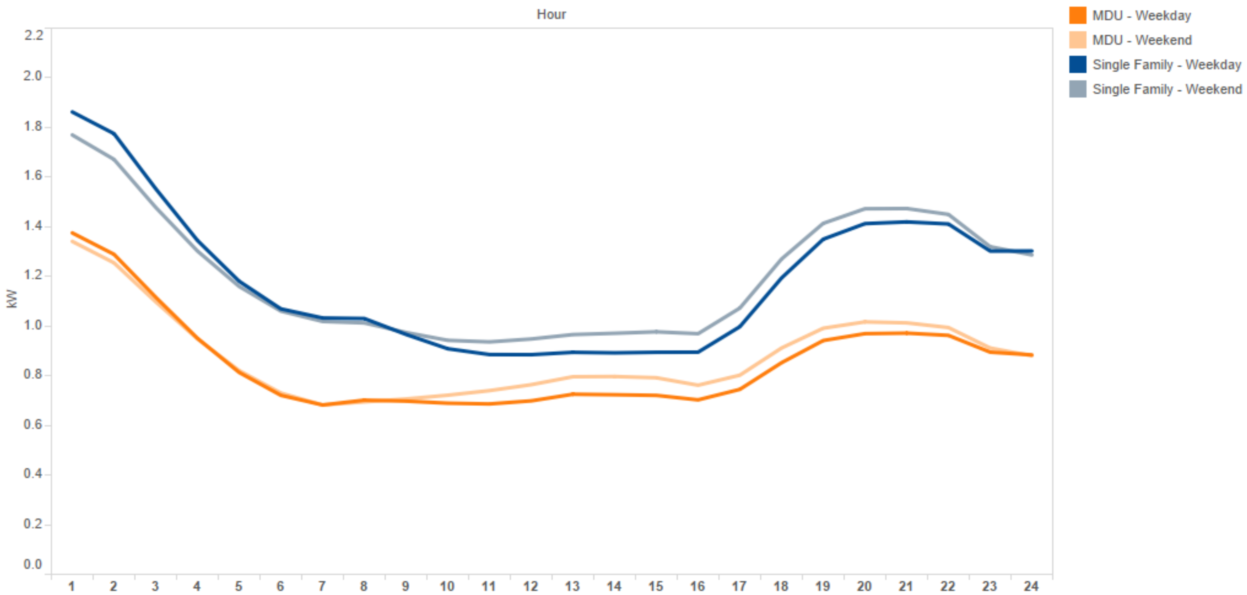


Chart PG&E-7a: Average Load Profile for SF and MDU Separately-Metered by Weekday and Weekend (2019)

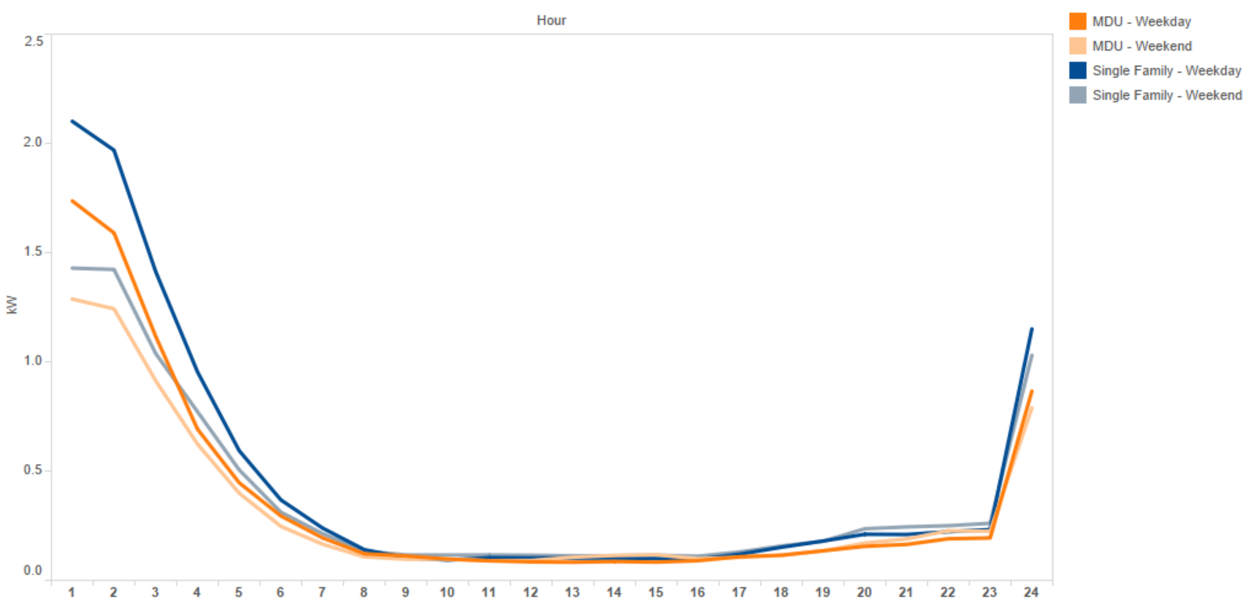
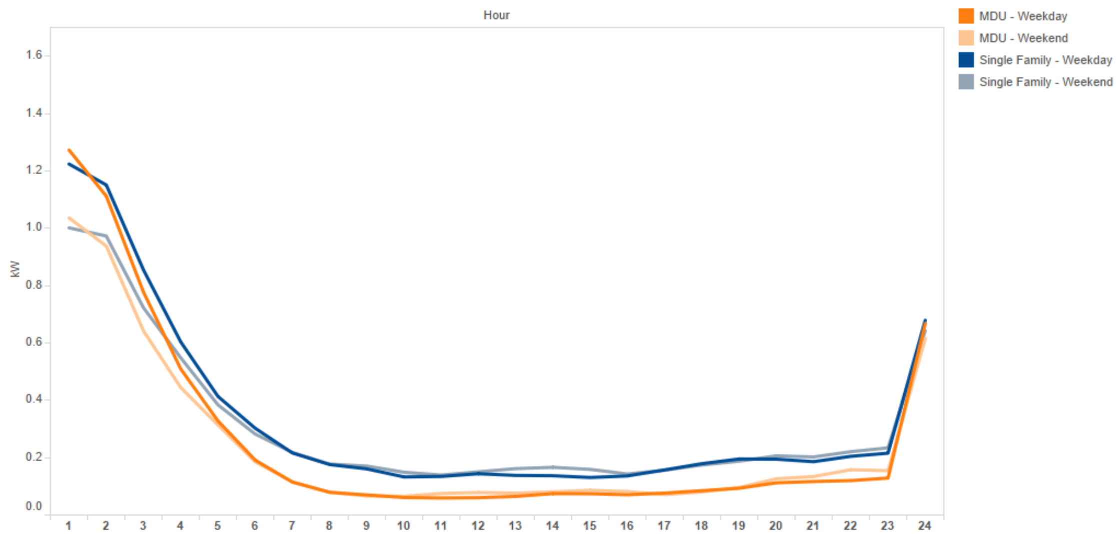


Chart PG&E-7b: Average Load Profile for SF and MDU Separately-Metered by Weekday and Weekend (2020)



Non-Coincident Peak Load

Collectively, the data in Tables PG&E-7a and 7b, and Charts PG&E-8a - 9b suggest that, even though charging is primarily occurring in the off-peak hours, the average household with a PEV will have a higher maximum demand that must be accommodated by the electric distribution system as compared to the average household without a PEV.

- Tables PG&E-7a and 7b show the monthly comparison of the average non-coincident peak for the single-metered and separately-metered customer sectors and the full residential population. The average non-coincident peak was 3.73 kW higher for the single-metered group category compared to the average residential peak,[22] in 2019, and in 2020 it was 3.18 kW higher. This was 3.3 kW higher for single family customers and 3.65 kW higher for multi-family customers in 2019, and 2.73 kW higher for single family customers and 3.44 kW higher for multi-family customers in 2020. The average non-coincident peak was 3.36 kW higher for the separately-metered group category compared to the average residential peak in 2019, and 2.47 kW higher in 2020.
- Tables PG&E-7a and 7b display the average monthly non-coincident peak loads for single-metered customers and separately-metered customers during 2019 and 2020, respectively.
- Charts PG&E-9a and 9b display the average monthly non-coincident peak loads for single-metered customers during 2019 and 2020, respectively.
- Charts PG&E-10a and 10b display the average monthly non-coincident peak loads for separately-metered customers during 2019 and 2020, respectively.

[22] The average non-coincident peak was calculated by denoting the maximum hourly interval for each account within the month. These maximum values were then summed for each category. The average is then calculated by dividing the total by the number of customers. The average non-coincident peak is therefore an approximation of the maximum demand for customer in each stratum.

Table PG&E-7a: Monthly Average Non-Coincident Peak Load (kW) (2019)

Year	Month	Residential Population*	Single Family Population*	MDU Population*	All Single-metered	Single Family Single-metered	MDU Single-metered	All Separately-metered	Single Family Separately-metered	MDU Separately-metered
2019	Jan	4.16	4.69	2.84	8.08	8.23	6.42	7.60	8.66	6.34
2019	Feb	4.37	4.93	2.96	8.13	8.27	6.49	7.48	8.56	6.18
2019	Mar	4.00	4.51	2.74	7.95	8.08	6.35	7.62	8.54	6.50
2019	Apr	3.84	4.33	2.59	7.84	7.98	6.27	7.67	8.76	6.33
2019	May	3.82	4.31	2.57	7.78	7.92	6.22	7.94	8.88	6.75
2019	Jun	4.53	5.18	2.91	8.50	8.66	6.71	7.79	8.56	6.81
2019	Jul	4.69	5.38	2.96	8.20	8.34	6.59	7.73	8.80	6.37
2019	Aug	4.87	5.59	3.07	8.50	8.64	6.84	7.79	8.75	6.55
2019	Sep	4.42	5.04	2.86	7.83	7.94	6.59	7.42	7.97	6.74
2019	Oct	3.85	4.33	2.63	7.46	7.56	6.31	7.30	7.97	6.46
2019	Nov	4.01	4.48	2.82	7.54	7.64	6.34	7.44	8.18	6.51
2019	Dec	4.27	4.80	2.93	7.81	7.93	6.48	7.37	7.95	6.63
Average		4.24	4.80	2.82	7.97	8.10	6.47	7.60	8.47	6.51

*Load data used for the analysis are from Jan 2019 to December 2019. (See footnote 20)

Table PG&E-7b: Monthly Average Non-Coincident Peak Load (kW) (2020)

Year	Month	Residential Population*	Single Family Population*	MDU Population*	All Single-metered	Single Family Single-metered	MDU Single-metered	All Separately-metered	Single Family Separately-metered	MDU Separately-metered
2020	Jan	4.16	4.69	2.84	7.60	7.71	6.36	7.01	7.20	6.75
2020	Feb	4.37	4.93	2.96	7.38	7.48	6.25	7.04	7.18	6.85
2020	Mar	4.00	4.51	2.74	7.23	7.32	6.16	6.50	6.51	6.49
2020	Apr	3.84	4.33	2.59	6.67	6.76	5.68	5.52	5.03	6.25
2020	May	3.82	4.31	2.57	7.19	7.29	6.12	6.61	6.77	6.38
2020	Jun	4.53	5.18	2.91	7.39	7.50	6.22	6.82	7.14	6.36
2020	Jul	4.69	5.38	2.96	7.43	7.53	6.26	6.83	7.16	6.34
2020	Aug	4.87	5.59	3.07	8.03	8.15	6.66	6.85	7.06	6.54
2020	Sep	4.42	5.04	2.86	7.79	7.90	6.49	6.68	6.77	6.55
2020	Oct	3.85	4.33	2.63	7.48	7.58	6.32	6.90	7.15	6.55
2020	Nov	4.01	4.48	2.82	7.33	7.43	6.23	6.93	6.95	6.90
2020	Dec	4.27	4.80	2.93	7.56	7.67	6.36	6.77	6.75	6.80
Average		4.24	4.80	2.82	7.42	7.53	6.26	6.71	6.81	6.56

*Load data used for the analysis are from Jan 2019 to December 2019. (See footnote 20)

Chart PG&E-8a: Average Non-Coincident Peak Load (kW) for Single-Metered by Customer Type by Month (2019)

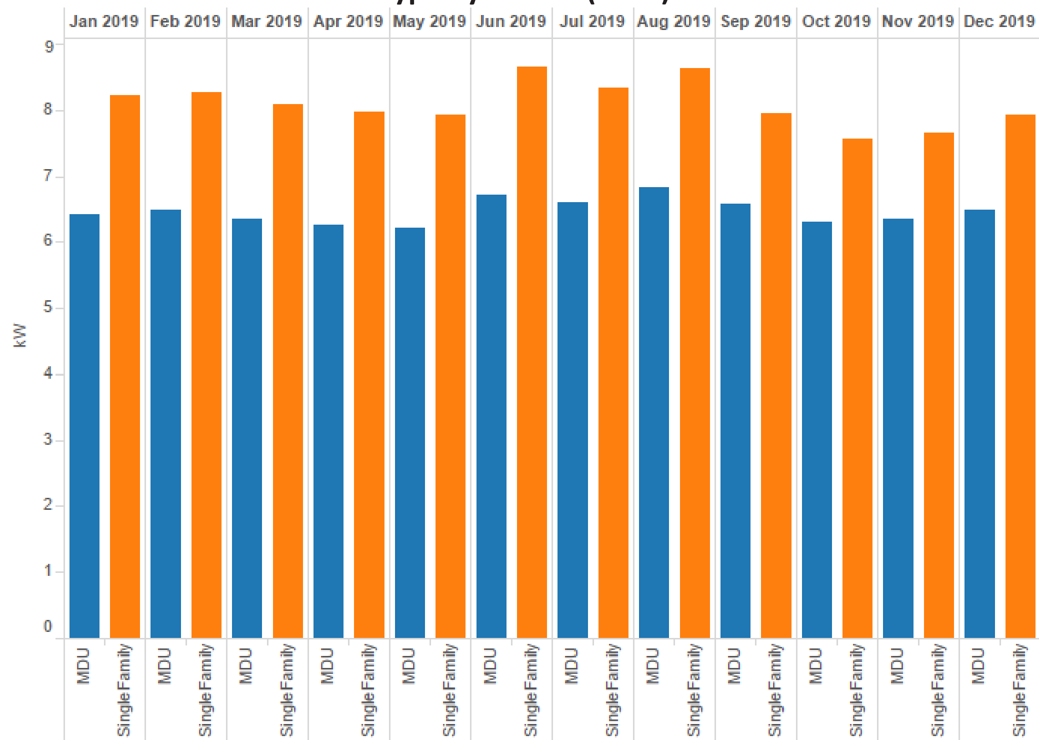


Chart PG&E-8b: Average Non-Coincident Peak Load (kW) for Single-Metered by Customer Type by Month (2020)

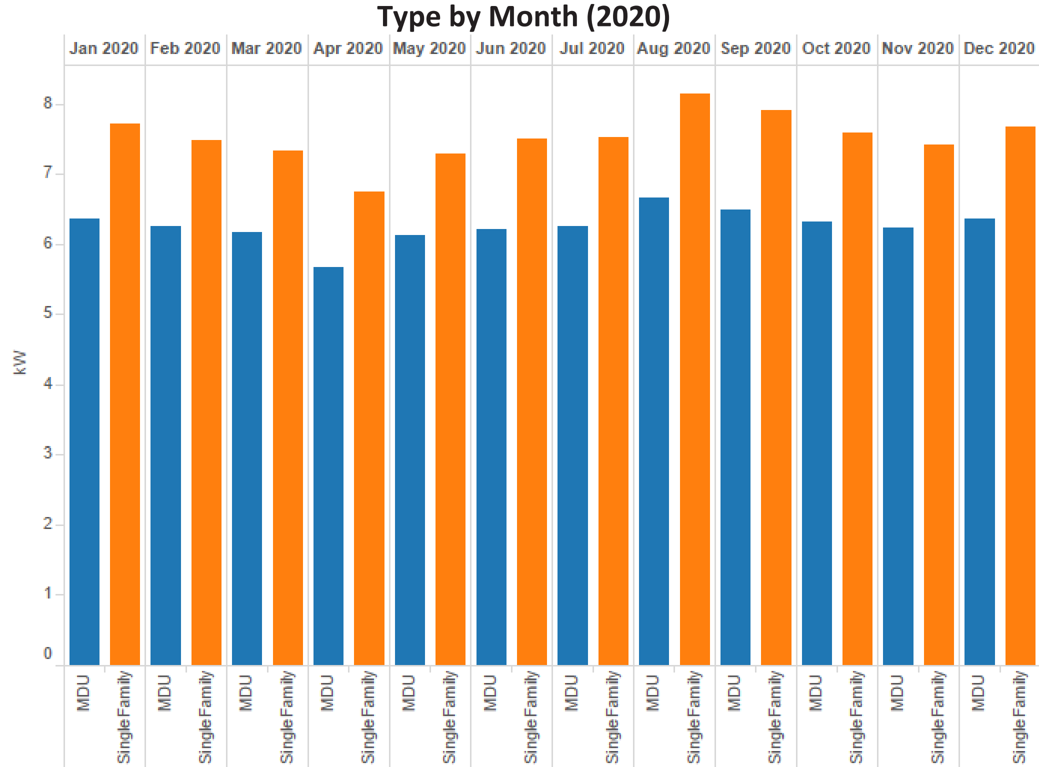


Chart PG&E-9a: Average Non-Coincident Peak Load (kW) for Separately-Metered by Customer Type by Month (2019)

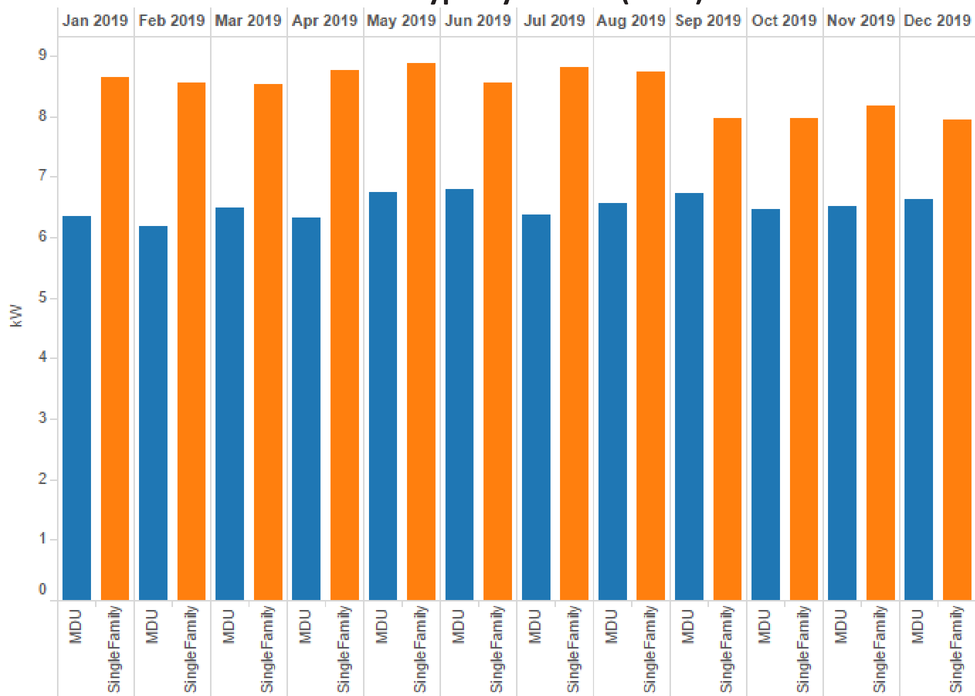
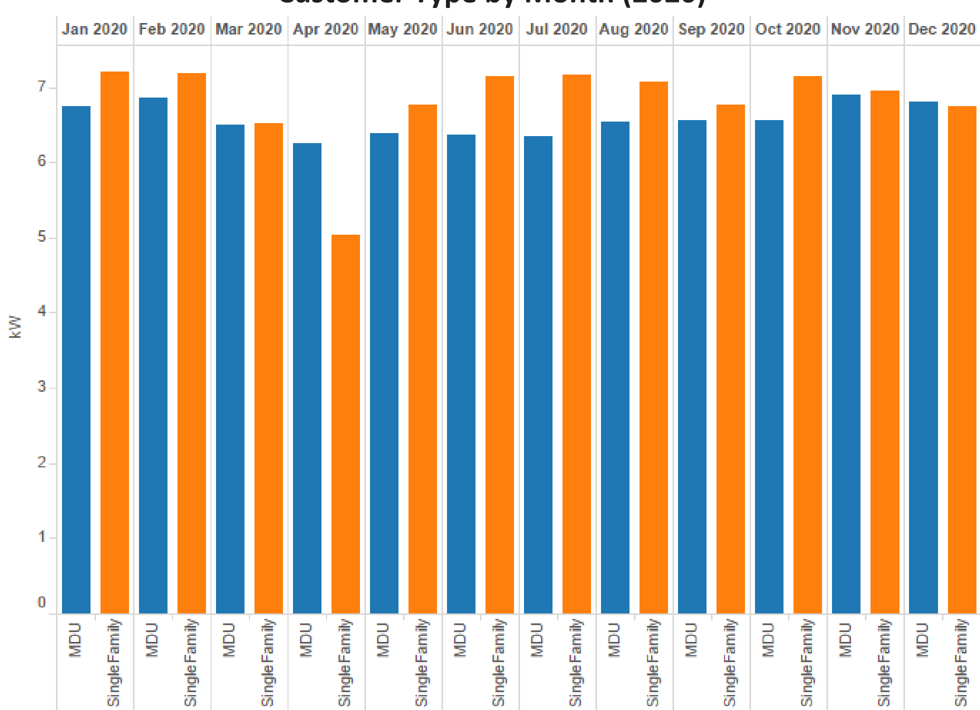


Chart PG&E-9b: Average Non-Coincident Peak Load (kW) for Separately-Metered by Customer Type by Month (2020)



Diversified Peak Load

The time of diversified peak load gives the time that the group peaks as a whole. The time of diversified (or group) peak load is generally the same for all categories of single-metered and separately-metered customers. Tables PG&E-8a-c show that the diversified peak load occurs between 1:00 a.m. to 2:00 a.m. for all categories in all months for both EV rates in 2019. Tables PG&E-9a-c show that the diversified peak load generally occurs between 1:00 a.m. to 2:00 a.m. for all categories in all months for both EV rates in 2020, except for a few months where the single-metered customers peaked at 7:00 p.m. and 8:00 p.m. This could be due to continued shelter-in-place orders combined with wildfire season influencing customers driving and charging behavior. The general trend of the data however, suggests that the early adopter group of customers on the PEV rates is charging during the off-peak periods thereby achieving the intent of the rate designs.

Table PG&E-8a: Time and Associated Demand of Diversified Peak Load – Entire Residential Population (2019)

Year	Month	Residential Population Demand*	Residential Population Hour	SF Population Demand	SF Population Hour	MDU Population Demand	MDU Population Hour
2019	Jan	1.04	13	1.27	13	0.74	18
2019	Feb	1.25	13	1.53	13	0.75	20
2019	Mar	1.26	14	1.56	14	0.64	21
2019	Apr	1.25	14	1.55	14	0.57	14
2019	May	1.23	14	1.53	14	0.54	13
2019	Jun	1.38	14	1.70	14	0.78	21
2019	Jul	1.38	14	1.68	14	0.78	17
2019	Aug	1.46	20	1.71	20	0.83	21
2019	Sep	1.21	14	1.48	14	0.73	20
2019	Oct	1.08	14	1.33	14	0.53	20
2019	Nov	0.97	13	1.18	13	0.68	18
2019	Dec	0.98	12	1.16	13	0.71	19

*Load data used for the analysis are from Jan 2019 to December 2019. (See footnote 20)

Table PG&E-8b: Time and Associated Demand of Diversified Peak Load – Single-Metered (2019)

Year	Month	Single-metered Demand	Single-metered Hour	SF Single-metered Demand	SF Single-metered hour	MDU Single-metered Demand	MDU Single-metered Hour
2019	Jan	2.99	1	3.06	1	2.12	1
2019	Feb	3.17	1	3.26	1	2.21	1
2019	Mar	2.98	1	3.05	1	2.14	1
2019	Apr	2.85	1	2.92	1	2.01	1
2019	May	2.81	1	2.88	1	2.01	1
2019	Jun	3.36	1	3.44	1	2.47	1

2019	Jul	2.98	1	3.05	1	2.13	1
2019	Aug	3.24	1	3.32	1	2.34	1
2019	Sep	2.87	1	2.94	1	2.16	1
2019	Oct	2.47	1	2.52	1	1.89	1
2019	Nov	2.47	1	2.52	1	1.84	1
2019	Dec	2.64	1	2.70	1	1.96	2

Table PG&E-8c: Time and Associated Demand of Diversified Peak Load – Separately-Metered (2019)

Year	Month	Separately-metered Demand	Separately-metered Hour	SF Separately-metered Demand	SF Separately-metered hour	MDU Separately-metered Demand	MDU Separately-metered Hour
2019	Jan	2.30	2	2.72	1	2.10	2
2019	Feb	2.52	1	3.12	1	2.33	1
2019	Mar	2.48	2	2.88	2	2.24	2
2019	Apr	2.51	1	2.93	1	2.12	2
2019	May	2.54	1	2.72	1	2.33	1
2019	Jun	2.27	1	2.52	1	2.08	1
2019	Jul	2.34	1	2.85	1	2.13	1
2019	Aug	2.48	1	2.97	1	2.04	1
2019	Sep	2.20	2	2.38	1	2.42	1
2019	Oct	2.09	2	2.29	1	2.29	1
2019	Nov	2.21	1	2.41	2	2.36	1
2019	Dec	2.19	1	2.42	1	2.29	1

Table PG&E-9a: Time and Associated Demand of Diversified Peak Load – Entire Residential Population (2020)

Year	Month	Residential Population Demand*	Residential Population Hour	SF Population Demand	SF Population Hour	MDU Population Demand	MDU Population Hour
2020	Jan	1.04	13	1.27	13	0.74	18
2020	Feb	1.25	13	1.53	13	0.75	20
2020	Mar	1.26	14	1.56	14	0.64	21
2020	Apr	1.25	14	1.55	14	0.57	14
2020	May	1.23	14	1.53	14	0.54	13
2020	Jun	1.38	14	1.70	14	0.78	21
2020	Jul	1.38	14	1.68	14	0.78	17
2020	Aug	1.46	20	1.71	20	0.83	21
2020	Sep	1.21	14	1.48	14	0.73	20
2020	Oct	1.08	14	1.33	14	0.53	20
2020	Nov	0.97	13	1.18	13	0.68	18
2020	Dec	0.98	12	1.16	13	0.71	19

*Load data used for the analysis are from Jan 2019 to December 2019. (See footnote 20)

Table PG&E-9b: Time and Associated Demand of Diversified Peak Load – Single-Metered (2020)

Year	Month	Single-metered Demand	Single-metered Hour	SF Single-metered Demand	SF Single-metered hour	MDU Single-metered Demand	MDU Single-metered Hour
2020	Jan	2.62	2	2.67	2	2.01	2
2020	Feb	2.55	1	2.60	1	1.95	1
2020	Mar	2.26	1	2.31	1	1.73	1
2020	Apr	1.47	1	1.50	1	1.10	1
2020	May	2.24	20	2.31	20	1.58	19
2020	Jun	2.17	20	2.23	20	1.53	19
2020	Jul	1.97	20	2.03	20	1.47	1
2020	Aug	2.56	19	2.63	19	1.90	1
2020	Sep	2.61	20	2.69	20	1.76	1
2020	Oct	1.97	1	2.01	1	1.53	1
2020	Nov	1.88	1	1.92	1	1.44	1
2020	Dec	2.01	1	2.06	1	1.50	1

Table PG&E-9c: Time and Associated Demand of Diversified Peak Load – Separately-metered (2020)

Year	Month	Separately-metered Demand	Separately-metered Hour	SF Separately-metered Demand	SF Separately-metered hour	MDU Separately-metered Demand	MDU Separately-metered Hour
2020	Jan	2.13	1	*2.23*	1	*2.47*	1
2020	Feb	2.30	1	*2.13*	1	*2.58*	1
2020	Mar	*1.79*	1	*1.82*	1	*1.99*	1
2020	Apr	*1.02*	1	*1.05*	1	*1.26*	2
2020	May	*1.39*	2	*1.63*	2	*1.25*	1
2020	Jun	*1.59*	1	*1.71*	1	*1.66*	1
2020	Jul	1.49	1	*1.71*	2	*1.64*	1
2020	Aug	*1.40*	1	*1.45*	2	*1.75*	1
2020	Sep	*1.44*	1	*1.44*	1	*1.80*	1
2020	Oct	*1.54*	1	*1.58*	1	*1.66*	1
2020	Nov	*1.66*	1	*1.90*	1	*1.80*	1
2020	Dec	*1.56*	1	*1.61*	1	*1.61*	2

*Italicized fields are estimates with a precision greater than +/- 10% at a 90% confidence interval.

Taken together, Tables PG&E-8a – 9c suggest that although the early adopter PEV customers may have a higher average maximum demand, those customers on the PEV rates tend to hit their maximum demand while non-PEV customers are at some of their lowest usage.
Thus, there is a diversity benefit created by the TOU rates. However, at the most local service assessment level perspective (i.e., a single household or set of households serviced by a single transformer), the value of this diversity is limited by the fact that the distribution system must

still be prepared to accommodate PEV charging during the peak period since these customers can, and occasionally do, charge during those times.

Non-Residential PEV Rates

Business EV Rate

As of the date of this report, PG&E has two non-residential PEV rates - the Business Low Use EV Rate (“BEV-1”) for customers with up to and including 100 kW demand for their PEV charging infrastructure and the Business High Use EV Rate (“BEV-2”) for customers with demand equal to 100kW and over for their EV charging infrastructure. Customers on the BEV-2 rate can be secondary or primary/transmission customers and have slightly different energy prices. The BEV rates work as a monthly subscription charge based on customers’ maximum monthly EV charging kW consumption. Both rate plans use a TOU rate structure. The TOU values vary a few cents between the BEV-1 and BEV-2 options, but follow largely the same structure: they offer on-peak, off-peak, and super off-peak energy prices according to the time periods in Table PG&E-10a. Regardless of season, or day of the week, both rates seek to encourage usage in off-peak hours. Both BEV rates include off-peak hours from 2:00 p.m. to 4:00 p.m. and 9:00 p.m. to 9:00 a.m. and super off-peak hours 9:00 a.m. to 2:00 p.m. during weekdays and weekends.

Table PG&E-10a: Tariff Type and Rate ($/kWh) in 2020

Hour	Rate: BEV-1 Every day including weekends and holidays, all year	Rate: BEV-2-S Every day including weekends and holidays, all year	Rate: BEV-2-P Every day including weekends and holidays, all year
12mn - 1am	$0.14089	$0.13508	$0.13179
1am - 2am	$0.14089	$0.13508	$0.13179
2am - 3am	$0.14089	$0.13508	$0.13179
3am - 4am	$0.14089	$0.13508	$0.13179
4am - 5am	$0.14089	$0.13508	$0.13179
5am - 6am	$0.14089	$0.13508	$0.13179
6am - 7am	$0.14089	$0.13508	$0.13179
7am - 8am	$0.14089	$0.13508	$0.13179
8am - 9am	$0.14089	$0.13508	$0.13179
9am - 10am	$0.11423	$0.11181	$0.10913
10am - 11am	$0.11423	$0.11181	$0.10913
11am - 12nn	$0.11423	$0.11181	$0.10913
12nn - 1pm	$0.11423	$0.11181	$0.10913
1pm - 2pm	$0.11423	$0.11181	$0.10913
2pm - 3pm	$0.14089	$0.13508	$0.13179
3pm - 4pm	$0.14089	$0.13508	$0.13179
4pm - 5pm	$0.33290	$0.34831	$0.34067
5pm - 6pm	$0.33290	$0.34831	$0.34067
6pm - 7pm	$0.33290	$0.34831	$0.34067
7pm - 8pm	$0.33290	$0.34831	$0.34067
8pm - 9pm	$0.33290	$0.34831	$0.34067
9pm - 10pm	$0.14089	$0.13508	$0.13179
10pm - 11pm	$0.14089	$0.13508	$0.13179
11pm - 12mn	$0.14089	$0.13508	$0.13179

Legend:

	All year
On	
Off	
Super Off	

* Rates effective through December 31, 2020. There is also a subscription component to the BEV rate. For details see Electric Schedule BEV, Business Electric Vehicles, retrieved from https://www.pge.com/tariffs/assets/pdf/tariffbook/ELEC_SCHEDS_BEV.pdf

Table PG&E-10b depicts price ratios for the TOU periods.

Table PG&E-10b: Price Ratios for 2020

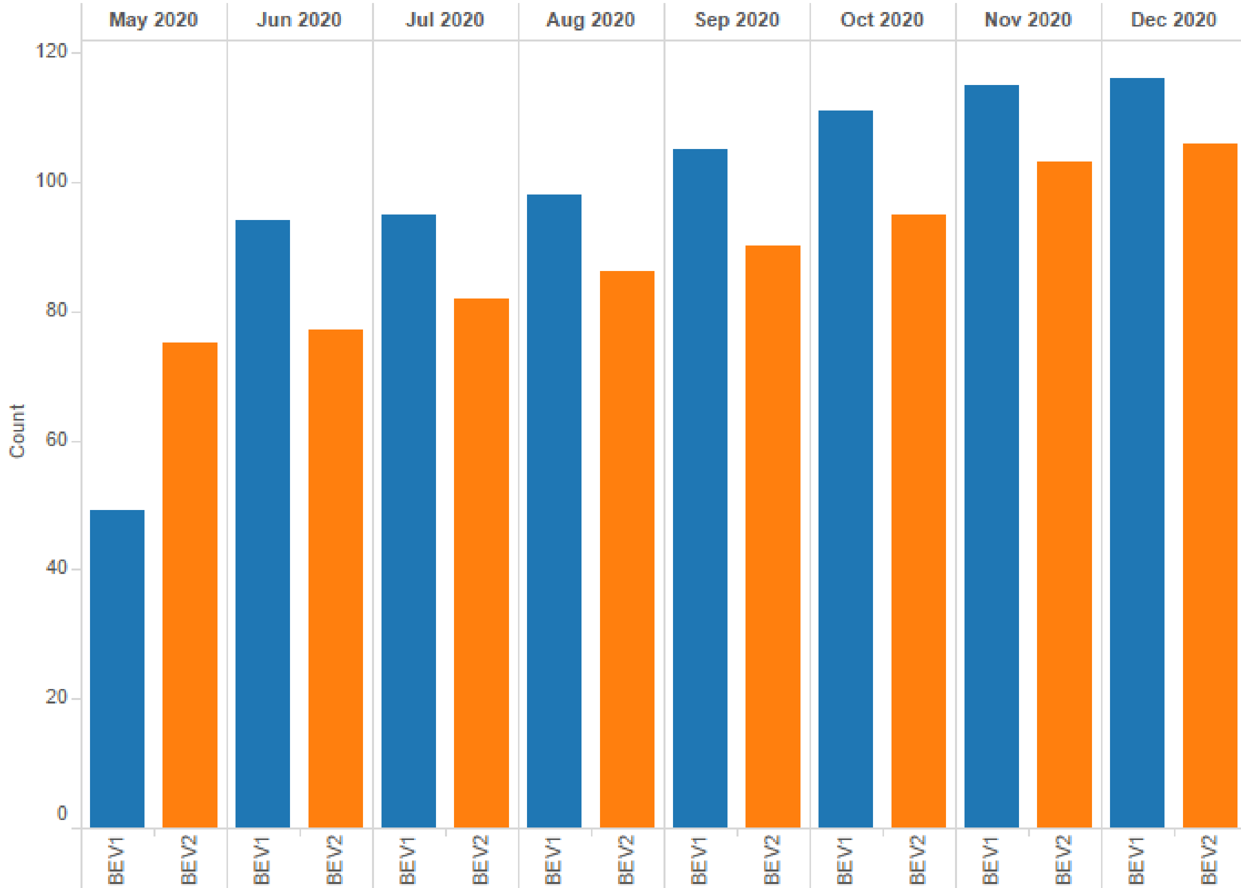
	BEV-1		BEV-2-S		BEV-2-P	
Season	Between Super-Off-Peak and On Peak	Between Super-Off-Peak and Off Peak	Between Super-Off-Peak and On Peak	Between Super-Off-Peak and Off Peak	Between Super-Off-Peak and On Peak	Between Super-Off-Peak and Off Peak
All year	0.34	0.81	0.32	0.83	0.32	0.83

BEV Rate Enrollment and Growth

Per Decision 19-10-055,[23] which approved a 2-phase launch, PG&E's BEV rate was launched with limited functionality in May 2020 and launched with full functionality in October 2020. There has been steady growth in enrollment for both the BEV-1 and BEV-2 rates since their launch. BEV-1 rate customers tend to be smaller businesses with fewer or smaller vehicles, or they are active in managing their charging. BEV-2 customers tend to be larger commercial customers such as transit operators with large vehicles, or charging sites with high utilization, often across multiple vehicles or fleets, such as DC Fast Charge operators. Since initial enrollment in the rate through the end of the study period, December 2020, BEV-1 accounts have increased 137% and BEV-2 accounts have increased 41%, as seen in Chart PG&E-10.

[23] Decision 19-10-055.

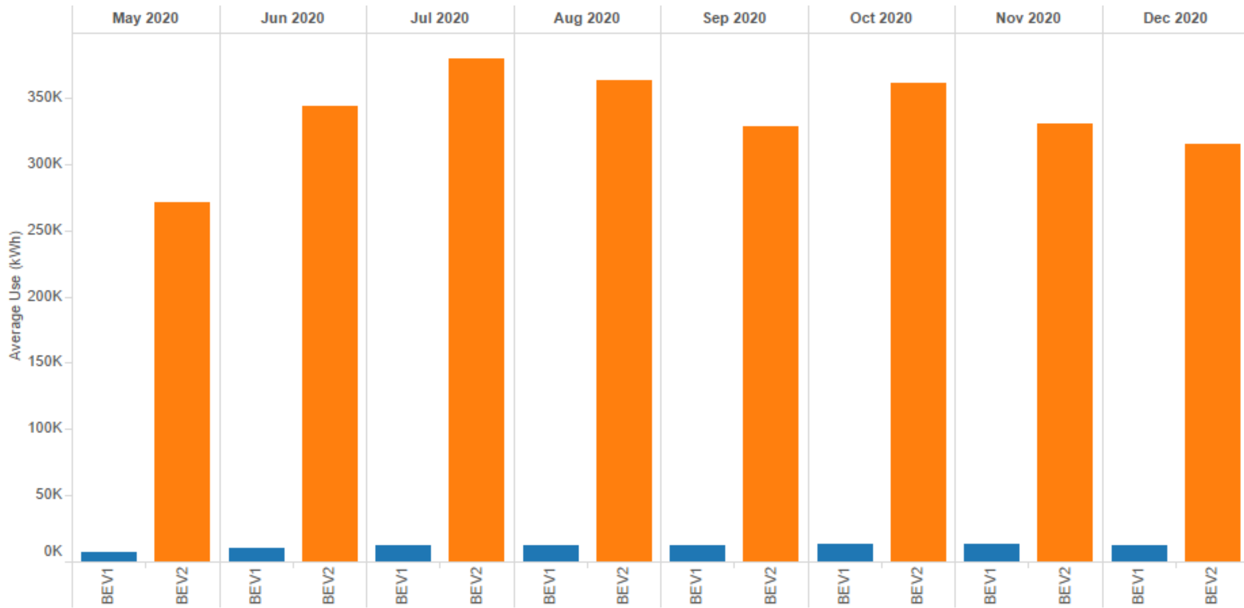
Chart PG&E-10: BEV Rate Accounts by Customer Type (2020)



Average Monthly Usage for BEV Rate Customers

Keeping in mind the cautions about the data collected mentioned in the section on residential PEV rates above, Chart PG&E-11 displays the average monthly usage for BEV-1 and BEV-2 customers in May through December 2020. As expected from the construct of the two rates, BEV-2 customers have a much higher average monthly usage than customers on BEV-1, although the customer sample for the two rates is still too small to make any conclusions.

Chart PG&E-11: BEV Average Monthly Usage (kWh) by Customer Type (BEV-1 and BEV-2) (2020)



Average Usage during Time of Use Periods

Similar to residential PEV rates, commercial BEV rates are designed to discourage charging during on-peak hours and encourage charging during off-peak and super off-peak hours. The time of use periods for both BEV rates are defined in Table PG&E-10a.

One useful way to determine whether the TOU PEV rates are achieving their goal of avoiding peak PEV charging is to measure the distribution of charging in the various time periods.

- Table PG&E-11a shows the share of on-peak, off-peak, and super off-peak usage for BEV-1 customers for the summer and winter seasons[24]. The energy usage is distributed relatively evenly between the three TOU periods, with slightly higher usage in the off-peak period. More charging could be occurring during the off-peak period than the super off-peak period due to the transportation needs of the customers. The super off-peak period occurs between 4 a.m. to 2 p.m. and many customers may need to be using their vehicles during this period and cannot be charging. However, the goal of BEV rates is to encourage customers to charge their vehicles during off-peak and super off-peak hours, the fact that the majority of BEV rate customers' usage is not during the peak period indicates that the EV TOU rates are achieving this goal among this group of PEV adopters. It is important to

[24] The BEV rate does not include any seasonality. Winter and Summer prices are the same. The distinction is included here to compare customer usage to different weather patterns and time of year.

note that the number of customers on the BEV-1 rate is small as it was recently opened to enrollment and therefore the energy usage of the average customer on said rate may change in the future as customer enrollment increases and the types of commercial customers utilizing the rate become more diverse

- Table PG&E-11b shows the share of on-peak, off-peak, and super off-peak usage for BEV-2 customers for the summer and winter seasons. The energy usage is distributed evenly between the three TOU periods, with slightly higher usage in the super-off peak and on-peak period than the off-peak period. This could be due to the unique and specific transportation needs of the customers on the BEV-2 rate. However, the goal of BEV rates is to encourage customers to charge their vehicles during off-peak and super off-peak hours. The fact that the majority of BEV rate customers' usage is not during the peak period indicates that the EV TOU rates are achieving this goal among this group of PEV adopters. It is important to note that the number of customers on the BEV-2 rate is small as it was recently opened to enrollment and therefore the energy usage of the average customer on said rate may change in the future as customer enrollment increases and the types of commercial customers utilizing the rate become more diverse

Collectively, Tables PG&E-11a and 11b show that the majority of energy usage of customers on the BEV rates does not occur during peak hours. BEV-1 customers are completing, on average, 69% of their charging during the off-peak and super off-peak period and BEV-2 customers are completing, on average, 66% of their charging during the off-peak and super off-peak period. This suggests that customers on the BEV rates are responding effectively to their rates' price signals and charging during the off-peak and super off-peak period.

Table PG&E-11a: Share of Usage for BEV-1 by TOU Period (2020)

Year	Season	On-Peak BEV-1	Off-Peak BEV-1	Super Off-Peak BEV-1
2020	Summer	32%	37%	30%
2020	Winter	29%	39%	32%
	Max	32%	39%	32%
	Avg	31%	38%	31%

* Numbers may not add up to 100% due to rounding

Table PG&E-11b: Share of Usage for BEV-2 by TOU Period (2020)

Year	Season	On-Peak BEV-2	Off-Peak BEV-2	Super Off-Peak BEV-2
2020	Summer	34%	33%	33%
2020	Winter	33%	33%	34%
	Max	34%	33%	34%
	Avg	33%	33%	33%

* Numbers may not add up to 100% due to rounding

Average Load Profiles for BEV Rates

Depicted below in Charts PG&E-12a and 12b are the average daily load profiles for BEV-1 and BEV-2 rate groups for weekday and weekend in 2020. The load profiles demonstrate that high off-peak usage corresponds to the PEV rate price signals, i.e., customers are largely responding to the price signal and charging during super off-peak hours (9:00 a.m. to 2:00 p.m.). There is still some charging that is occurring during peak hours (4:00 p.m. to 9:00 p.m.) which is likely due to inflexibility of business needs and/or use of public charging by customers on their commute home. As expected from the rate design, the average kW demand is higher for BEV-2 customers and the BEV-2 customer load profiles does show that customers are charging during the super off-peak period. It also shows that BEV-2 customers are also still charging during some of the on-peak hours which may be attributable to the DCFC customers who are less aware of the TOU price signals or less able to adjust their charging time. The lower usage during the off-peak period despite the low energy prices may be a result of the ability to charge during the middle of the day to meet business needs as well as limited use of public charging by customers during those hours. There is very little difference between the weekday and weekend load profiles for both rates which may suggest that BEV rate customers have similar business operations and charging needs throughout the week. [25] However, this may change as more customers with varying business operations and needs enroll in the rate.

[25] Weekend and weekday prices are the same on the BEV rates as are the TOU periods. Therefore, any change in charging pattern between weekend and weekday should not be attributed to differences in price signal.

Chart PG&E-12a: Average Load Profile for BEV-1 Customer by Weekday and Weekend (2020)

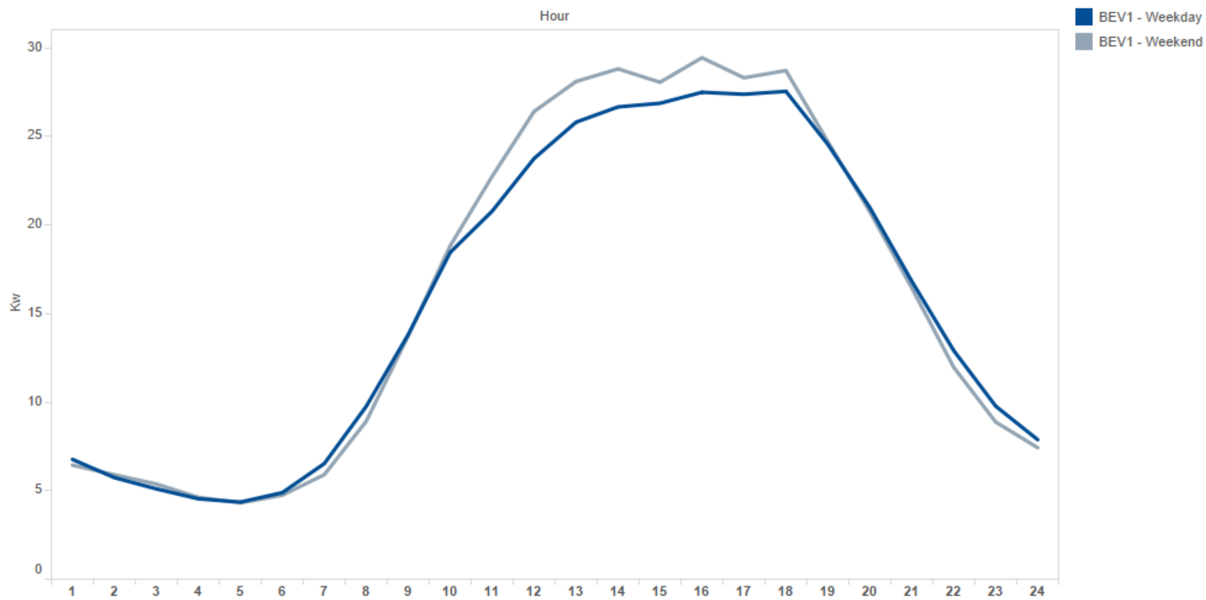
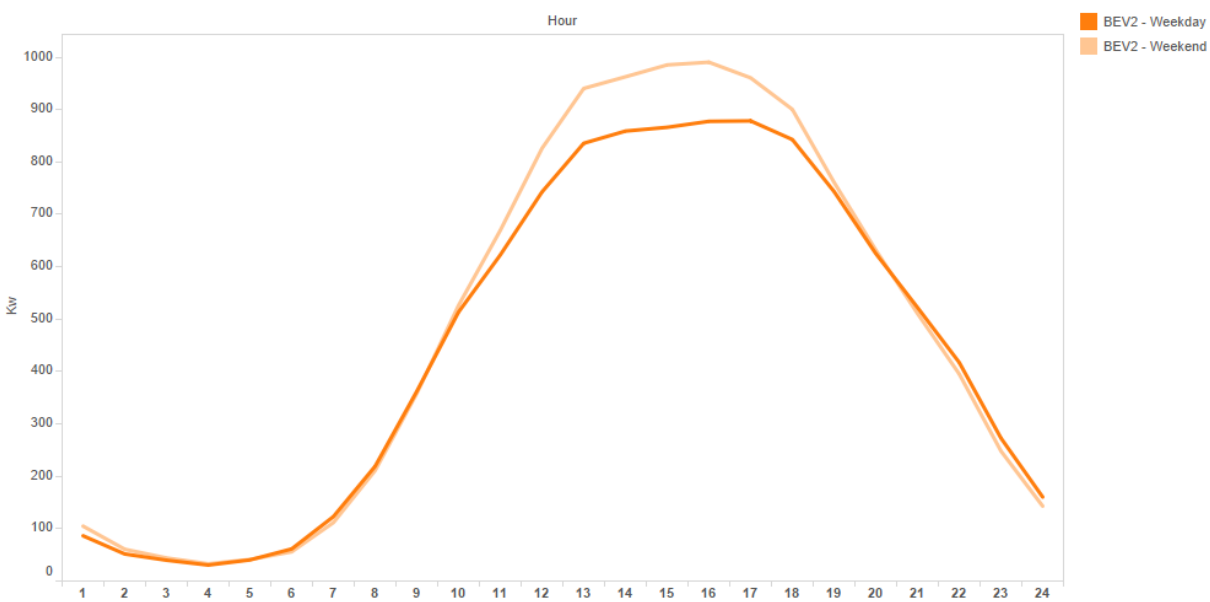


Chart PG&E-12b: Average Load Profile for BEV-2 Customer by Weekday and Weekend (2020)



Non-Coincident Peak Load

To compare non-coincident peak loads, the two BEV rates were compared to commercial customers on commercial rates with similar kW demand. The BEV-1 rate was compared to a general population on the A-10 rate, which are commercial customers with kW demand that does not exceed 499 kW. The peak load on the BEV-2 rate was compared to that of customers on the E-19 rate, who are customers with 500 kW demand or higher. Similar to residential customers, the average commercial customer with charging installations will generally have a higher maximum demand that must be accommodated by the electric distribution system as compared to the average commercial customer without PEV charging installations.

- Table PG&E-12 shows the monthly comparison of the average non-coincident peak between BEV-1 and A-10 customers, and between BEV-2 and E-19 customers. The average non-coincident peak was 33.47 kW higher for the BEV-1 group category compared to the average A-10 commercial population peak.[26] For the BEV-2 group, the average non-coincident peak was 101.65 kW higher compared to the average E-19 commercial population peak. Chart PG&E-13 shows a monthly average non-coincident peak load for each rate.

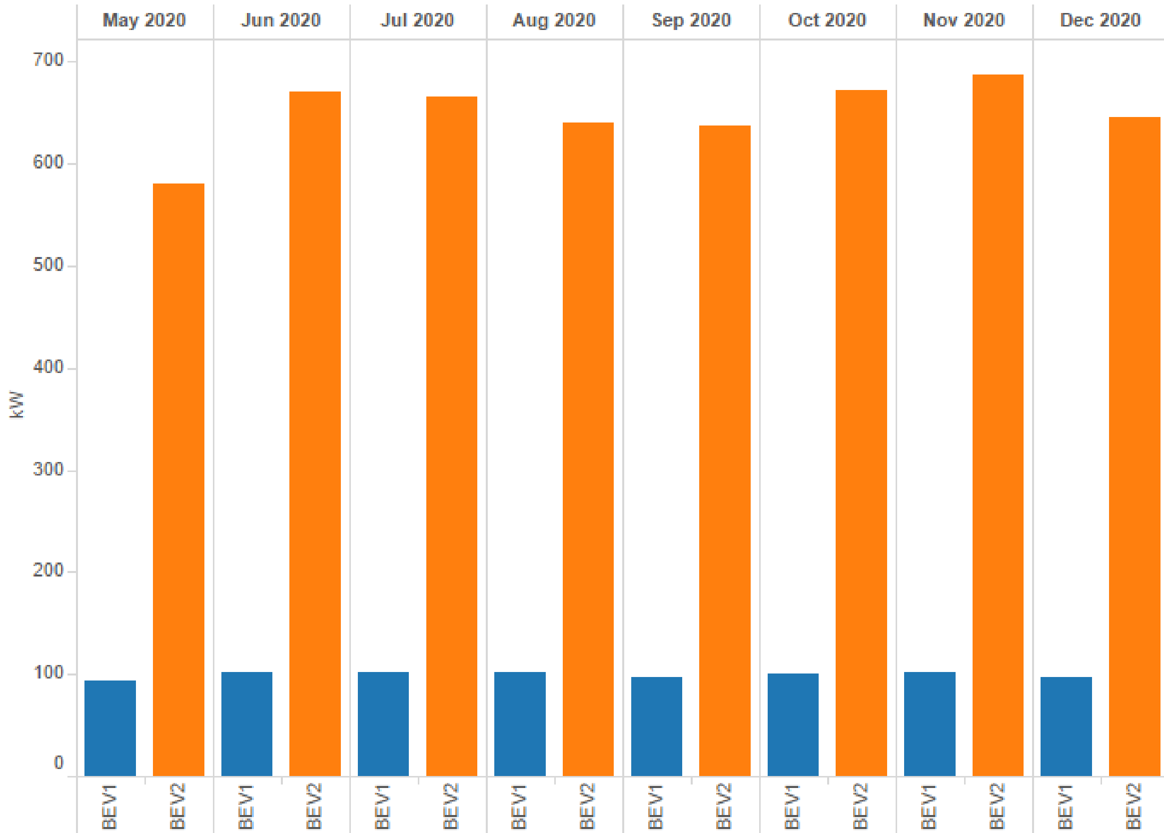
Table PG&E-12: Monthly Average Non-Coincident Peak Load (kW) (2020)

Year	Month	Non-Residential A-10 Population*	BEV-1**	Non-Residential E-19 Population*	BEV-2
2020	May	63.01	93.03	524.91	579.76
2020	Jun	71.01	101.26	603.01	670.65
2020	Jul	66.47	101.89	568.10	665.67
2020	Aug	73.49	102.45	609.54	641.19
2020	Sep	71.47	97.00	587.01	636.41
2020	Oct	64.49	100.88	532.82	671.61
2020	Nov	60.23	102.28	498.65	688.06
2020	Dec	58.13	97.33	461.38	645.31
	Average	66.04	99.51	548.18	649.83

*Load data used for the analysis are from Jan 2019 to December 2019. (See footnote 20)
** BEV1 limit is 100kW. Usage may exceed 100kW if a customer overextends their charging and exceeds 100kW, in which case overage fees are applied per kW over 100kW.

[26] The average non-coincident peak was calculated by denoting the maximum hourly interval for each account within the month. These maximum values were then summed for each category. The average is then calculated by dividing the total by the number of customers. The average non-coincident peak is therefore an approximation of the maximum demand for customer in each stratum.

Chart PG&E-13: Average Non-Coincident Peak Load (kW) by Customer Type (BEV-1 and BEV-2) by Month (2020)



Diversified Peak Load

Different than the residential PEV rates, the time of diversified (or group) peak load for both BEV rates is reached during the afternoon and early evening hours. Table PG&E-13 shows that the diversified peak load occurs between 2:00 p.m. and 6:00 p.m. for BEV-1 customers and between 1:00 p.m. and 4:00 p.m. for BEV-2. This suggests that customers on the BEV-2 rate are peaking during non-peak hours, generally achieving the intent of the time-of-use structure. The BEV-1 customers are primarily peaking at approximately the 4:00 p.m. mark, with a few months peaking an hour or two later, crossing the threshold into the peak period pricing TOU period. This may be due to the type of customers enrolled on the BEV-1 rate and their charging needs. Due to the newness of the rate and the limited amount of data, this doesn't necessarily indicate a continued trend of on-peak max demand in subsequent months.

Table PG&E-13: Time and Associated Demand of Diversified Peak Load – Entire Residential Population (2020)

Year	Month	Non-Residential A-10 Population Demand*	Non-Residential A-10 Population Hour*	BEV-1 Demand	BEV-1 Hour	Non-Residential E-19 Population Demand*	Non-Residential E-19 Population Hour*	BEV-2 Demand	BEV-2 Hour
2020	May	34.83	14	40.91	16	362.57	14	1,110.81	15
2020	Jun	42.14	14	54.64	16	442.35	14	1,518.24	14
2020	Jul	38.85	14	58.21	14	402.15	15	1,581.27	15
2020	Aug	44.77	14	52.78	17	435.97	14	1,442.46	16
2020	Sep	42.86	14	59.06	16	422.77	15	1,376.23	13
2020	Oct	35.40	15	58.55	16	366.01	15	1,432.56	16
2020	Nov	29.74	14	57.86	17	344.16	14	1,413.66	13
2020	Dec	29.30	9	57.40	18	317.23	13	1,291.46	15

*Load data used for the analysis are from Jan 2019 to December 2019. (See footnote 20)
Highlighted fields are estimates with precision > +-10% at 90% CI.

Table PG&E-13 shows that BEV customers, particularly BEV-2 customers, have significantly higher demand than the non-PEV, non-residential customers. It also shows that BEV rate customers and non-PEV, non-residential rate customers are hitting their maximum demand around the same time. This may change as more customers with diverse business needs enroll in the BEV rate. However, even if BEV customer peak load occurs at a different time than the general non-PEV, non-residential customer peak load, the local service and distribution system must still be prepared to accommodate PEV charging during the peak period since these customers can still charge during those times.

Transportation Electrification Program Load Data
Average Monthly Usage for PG&E Pilots/Programs

The average monthly utilization in Charts PG&E-14a and PG&E-14b shows utilization for PG&E's Electric Vehicle Charge Network (EVCN) program. As seen in Chart PG&E-14a, the average monthly utilization per-port in 2019 peaked during the summer months among Workplace (WP) sites while utilization at multi-unit dwelling (MUD) sites grew, but at a significantly slower rate. Per port utilization across WP sites could be due to the activation of ports at particular sites that showed high utilization during the summer months in 2019 and, possibly, the growth in charging demand as more ports became available.

While utilization remained relatively high in early 2020, COVID-19 restrictions drove down utilization from March onwards. Chart PG&E-14b shows that utilization at the onset of 2020 reached almost 260 kWh per port in January for WPs, and fell to approximately 40-50 kWh per port for both MUDs and WPs for the rest of the year following shelter-in-place orders during spring 2020. While absolute rates fell in Q2 2020, utilization did grow from April 2020 through December 2020 (with December kWh/port higher than April for WPs and MUDs by ~57% and ~27% respectively).

Chart PG&E-14a: PG&E EVCN Program Average Monthly Usage (kWh) by Port (2019)

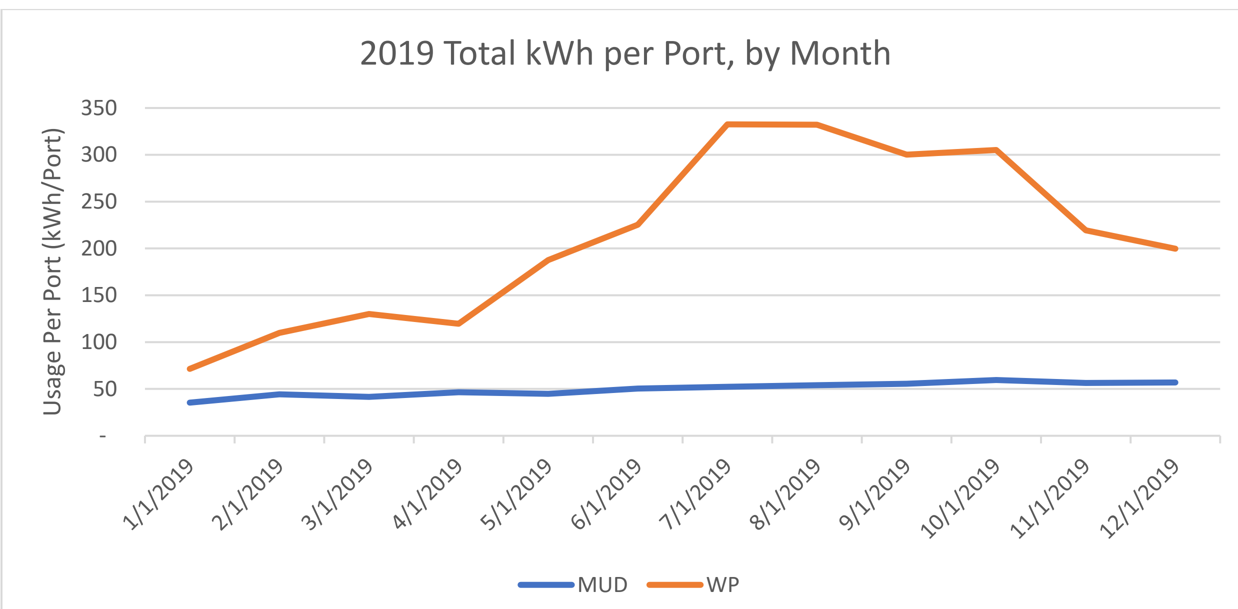
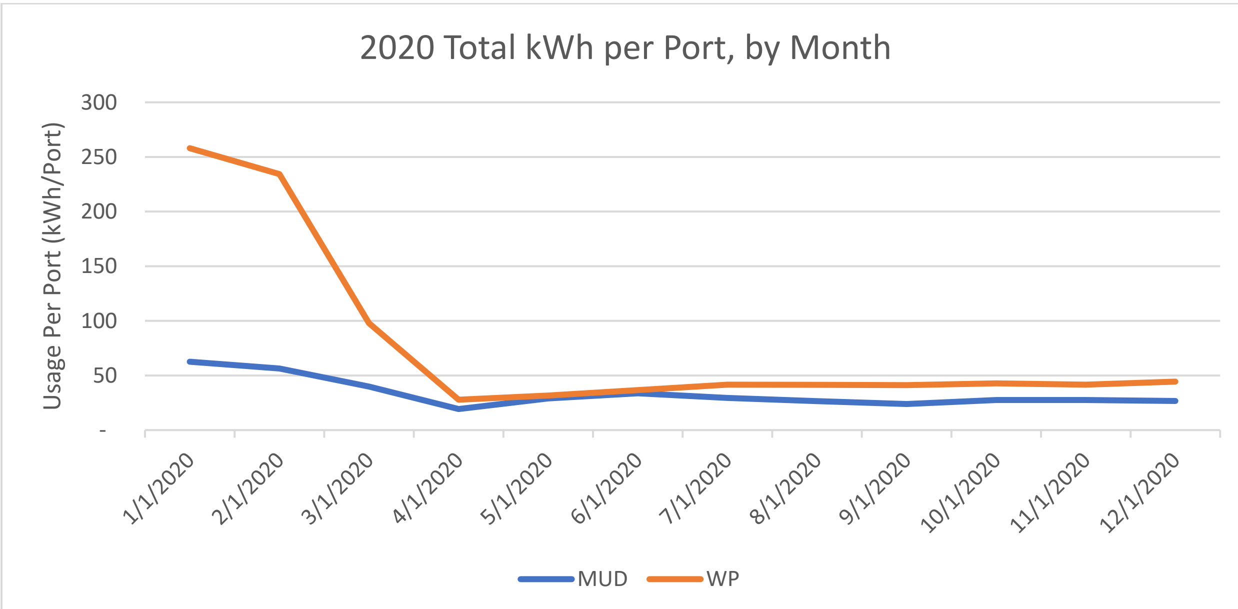


Chart PG&E-14b: PG&E EVCN Program Average Monthly Usage (kWh) by Port (2020)



Average Load Profiles for PG&E Pilots/Programs

Charts PG&E-15a and PG&E-15b show the annual average weekday load profiles per port at MUD and WP sites in 2019. The average load profile for usage at MUDs show more variation than ports at WPs throughout the day. During 2019, MUD sites experienced utilization peaks during the middle of the day between 9:00 AM and 1:00 PM, as well as at the end of the day between 7:00 PM and midnight. In contrast, ports at WP sites, on average, experienced one larger peak during the middle of the day between 9:00 AM and 3:00 PM. Given that commuters most likely visit workplaces during business hours, it is sensible that utilization would peak during the middle of the day.

Similarly, utilization at WP sites during the weekend peaks between the late morning and mid afternoon – 11:00 AM to 5:00 PM – as seen in Chart PG&E-15c. Ports at MUDs showed, on average, higher usage during the weekends than WPs with a peak between 4:00 PM and midnight.

Chart PG&E-15a: MUD Average Weekday Load Profile (kWh) per Port (2019)

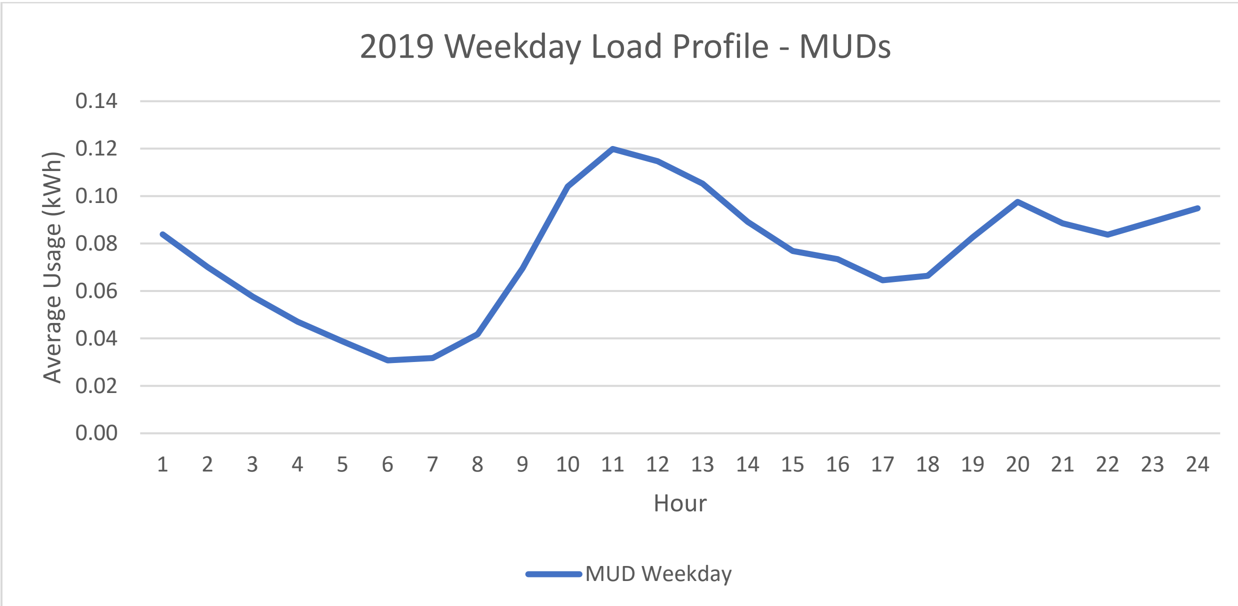


Chart PG&E-15b: WP Average Weekday Load Profile (kWh) per Port (2019)

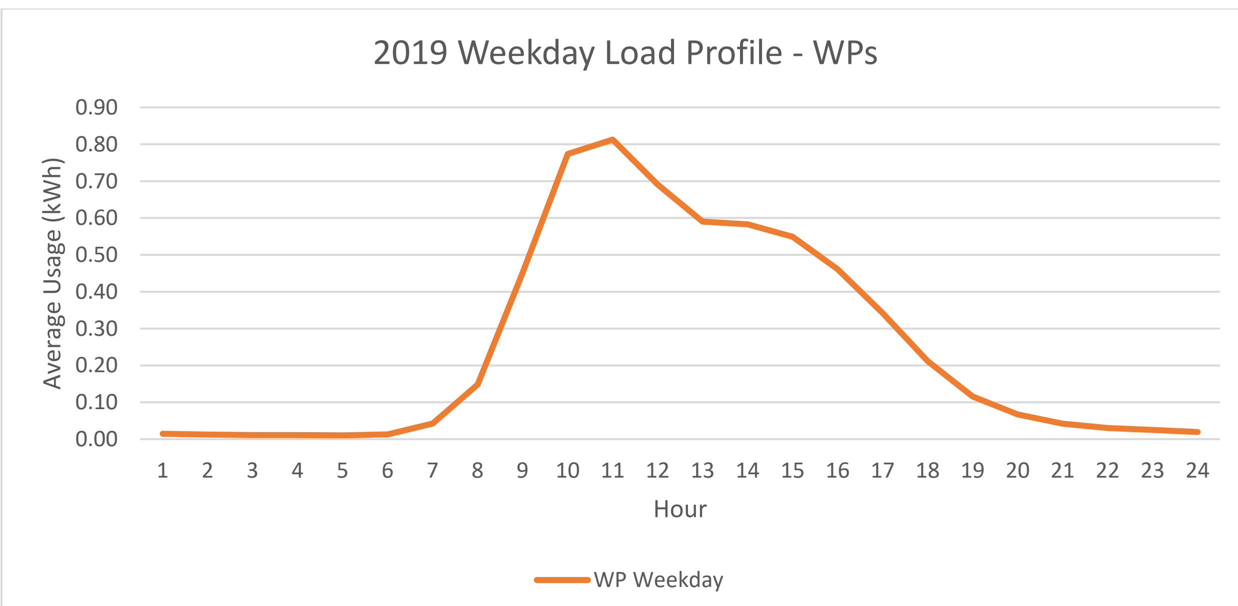
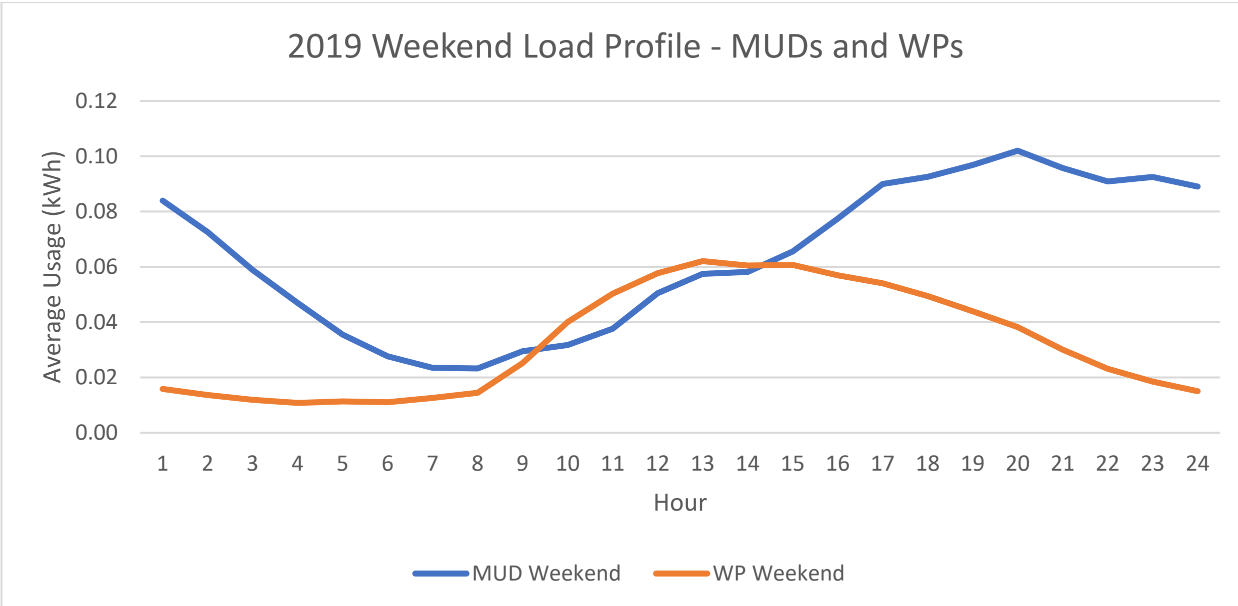


Chart PG&E-15c: WP and MUD Average Weekend Load Profile (kWh) per Port (2019)



Charts PG&E-16a and PG&E-16b show annual average weekday load profiles per port at MUD and WP sites during 2020. The average weekday load profile for usage at MUDs show similar trends in utilization compared to 2019 – midday and end of day peaks, as seen in Chart PG&E-15a. The usage, however, is relatively lower during those peaks compared to 2019. This could be as a result of a large fraction of the workforce working from home due to shelter-in-place orders that may have impacted commutes and vehicle-miles traveled overall. Port utilization at WPs, as shown in Chart PG&E-16b, also experienced a similar trend to 2019. Peaks occured during typical business hours – 9:00 AM to 5:00 PM – with relatively lower usage compared to 2019.

Chart PG&E-16c shows the annual average weekend load profiles for ports at MUD sites and WP sites during 2020. Similar to 2019, peak utilization at WP sites spanned the typical business hour range, 9:00 AM to 4:00 PM. Ports at MUD sites also showed similar utilization trends compared to 2019. Peaks occurred during the second half of the day beteween 4:00 PM and midnight. While similar in load behavior, ports at both WPs and MUDs show lower kWh demand per port during their peaks relative to 2019. Similar to weekday average load profiles, this could be a result of shelter-in-place orders.

Chart PG&E-16a: MUD Average Weekday Load Profile (kWh) per Port (2020)

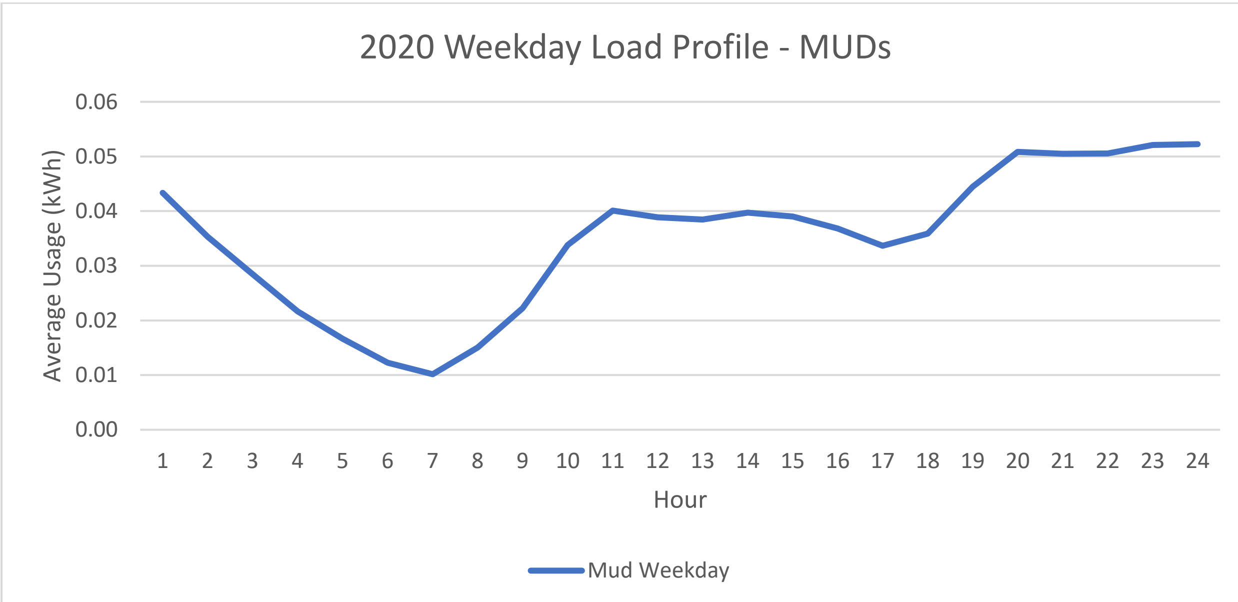


Chart PG&E-16b: WP Average Weekday Load Profile (kWh) per Port (2020)

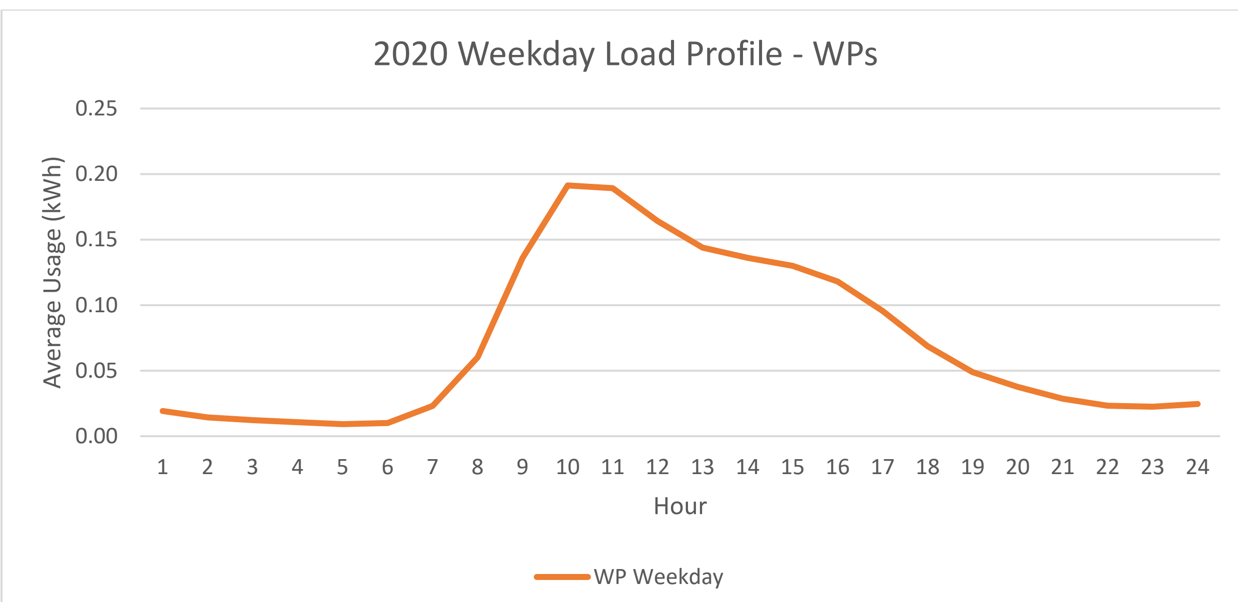
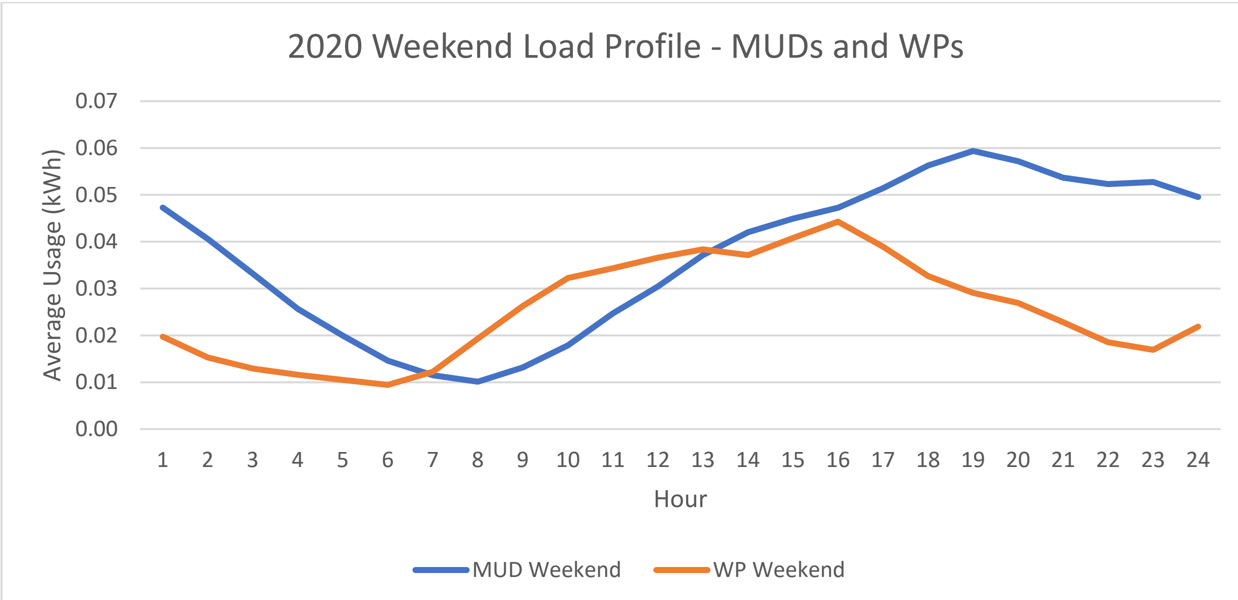


Chart PG&E-16c: WP and MUD Average Weekend Load Profile (kWh) per Port (2020)



More data on PG&E's EVCN Program can be found in the quarterly updates to the Program Advisory Council and EVCN Quarterly Reports. [27]

Average Utilization for PG&E Priority Review Projects

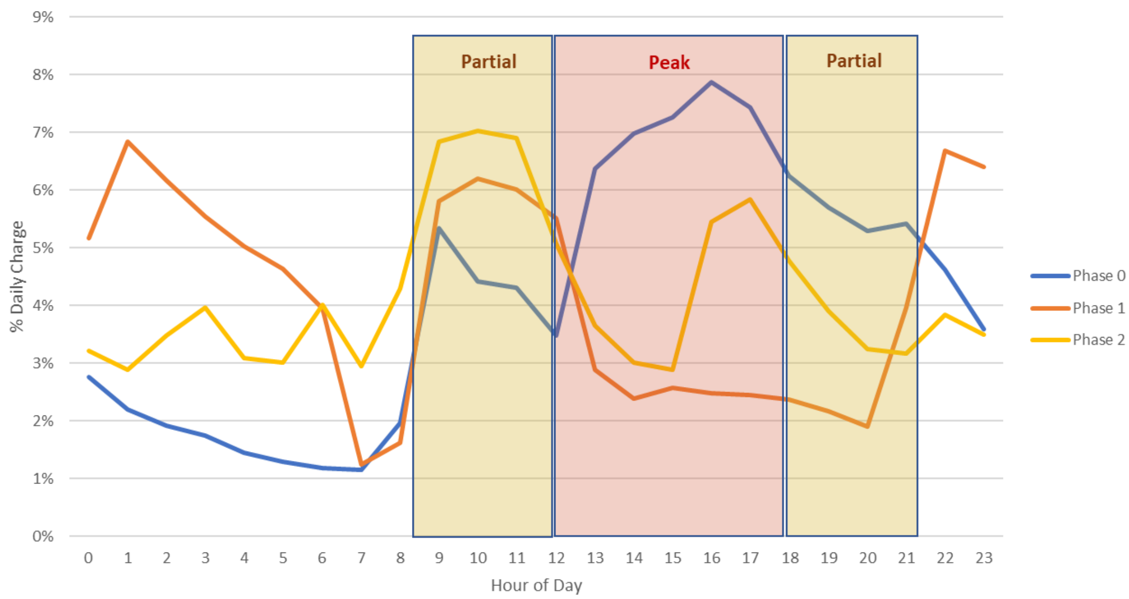
PG&E managed four Priority Review Projects (PRPs) including the Electric School Bus Renewables Integration Project, the Idle Reduction Technology Project, and the Medium/Heavy Duty (MD/HD) Customer Fleet Demonstration Project, and the Home Charger Resource Pilot. The Home Charger Resource Pilot is not included as part of this report as it does not include infrastructure installation costs. The Electric School Bus Renewables Integration pilot explored whether a school district could reduce total cost of ownership (TCO) by minimizing infrastructure and fuel costs and whether school buses could act as a distributed energy resource during periods of high renewable penetration. The Idle Reduction Technology Project focused on the electric standby transport refrigeration unit (eTRU) market. The objectives of this PRP were to (1) demonstrate a lower TCO for the technology through minimizing fuel and infrastructure costs, (2) develop lessons learned to share with other distribution facilities supporting PG&E's EV Fleet program, and (3) reduce emissions of harmful pollutants from diesel engines. Lastly, for the Medium/Heavy Duty Customer Fleet Demonstration PRP, the primary goal was to demonstrate if, with support from the utility, fleet managers could lower the TCO for MD/HD electric fleets relative to fossil fuel alternatives. This report references the utilization for each PRP documented in their respective Evaluation Reports. For further details

[27] Program Advisory Council quarterly updates are publicly available here.

and full results of each program, please reference their individual reports, which will be published separately and simultaneously. Note that the Evaluation Reports for each PRP were drafted and filed in parallel to this report. For final results, reference the individual reports.

ELECTRIC SCHOOL BUS RENEWABLES INTEGRATION PILOT

Chart PG&E-17: Weedkay Load Profiles: Pilot Phases 0, 1, and 2



The Electric School Bus Renewables Integration pilot consisted of four phases to explore a series of increasingly complex charge management uses with the Pittsburgh Unified School District (PUSD). Phase 0 (Baseline) tested the impacts of uncontrolled school bus charging immediately upon being plugged in. Phase 1 (Static Scheduled Charging) involved a charge management platform that managed charging according to PUSD's static TOU rate schedule (A-6). Phase 2 (Excess Supply Demand Response Pilot (XSP)[28], Participation) added demand response functionality through participation in PG&E's XSP, while Phase 3 (Renewables Self-Consumption, simulation) adjusted charging schedules to optimize consumption from on-site renewable generation. Finally, Phase 4 (Renewables Optimization, simulation) combined phases 1, 2 and 3 to minimize bill impacts.

Performance varied significantly between each phase in terms of the time of day of charging behavior, the average cost of electricity incurred, and the GHG emissions associated with electric bus energy. Chart PG&E-17 shows the share of total daily energy delivered during each hour in Phases 0, 1, and 2. During Phase 0 (in blue), buses began charging immediately upon being plugged in, with no application of any load management practices. During Phase 1 (in

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[28] XSP tests the capabilities of price-responsive demand-side resources to shift or increase load as a service to the grid during times of anticipated excess supply of renewables generation or negative wholesale energy prices. Depending on market conditions, participants may be asked to increase their usage during certain hours of the day (https://www.pge.com/en_US/large-business/save-energy-and-money/energy-management-programs/energy-incentives.page).

orange), on the other hand, a charge management system was in place and charging activity was scheduled to avoid Peak tariff windows. The low demand between 1PM and 8PM during Phase 1 aligns with a concerted effort to avoid the 12:00-6:00 PM Peak window of the A-6 Summer tariff.[29] During Phase 2 (in yellow), charging activity was generally structured to follow the same static charging schedule as implemented in the Phase 1 schedule; however, charging activity in response to XSP events and the energy consumption of a bus delivered in October that was not configured to respond to charge management signals caused divergences relative to Phase 1.

Table PG&E-14: Effects of Managed Charging Protocol

	Phase 0	Phase 1	Phase 2
Share charging during Peak hours	46%	21%	31%
Share charging during Partial Peak hours	32%	28%	35%
Share charging during Off Peak hours	22%	52%	34%
Average Electric fuel cost ($/kWh)	$0.21 [a]	$0.17 [a]	$0.02 [b]

Additionally, as shown in Table PG&E-14, compared to Phases 0 and 1, the charging activity during Phase 2 was more evenly spread across Peak, Partial Peak, and Off-Peak hours. All the XSP events called during Phase 2 occurred between 8 AM and 1 PM, which are Peak and Partial Peak hours according to the summer A-6 tariff. This means that when charging activity in Phase 2 deviated from the static charging schedule to respond to XSP events, it was likely to result in shifting charging activity away from Off Peak consumption on those days. The trends are further diluted because one of the buses that was introduced during Phase 2 was not capable of delayed charging, yet its consumption is inherently included in the meter data summarized in Table PG&E-14. The average calculated fuel cost during Phase 2 was exceptionally low compared to the prior phases because the fleet benefited from application of NEM2A credits generated by the of solar that was interconnected on August 16, 2019.

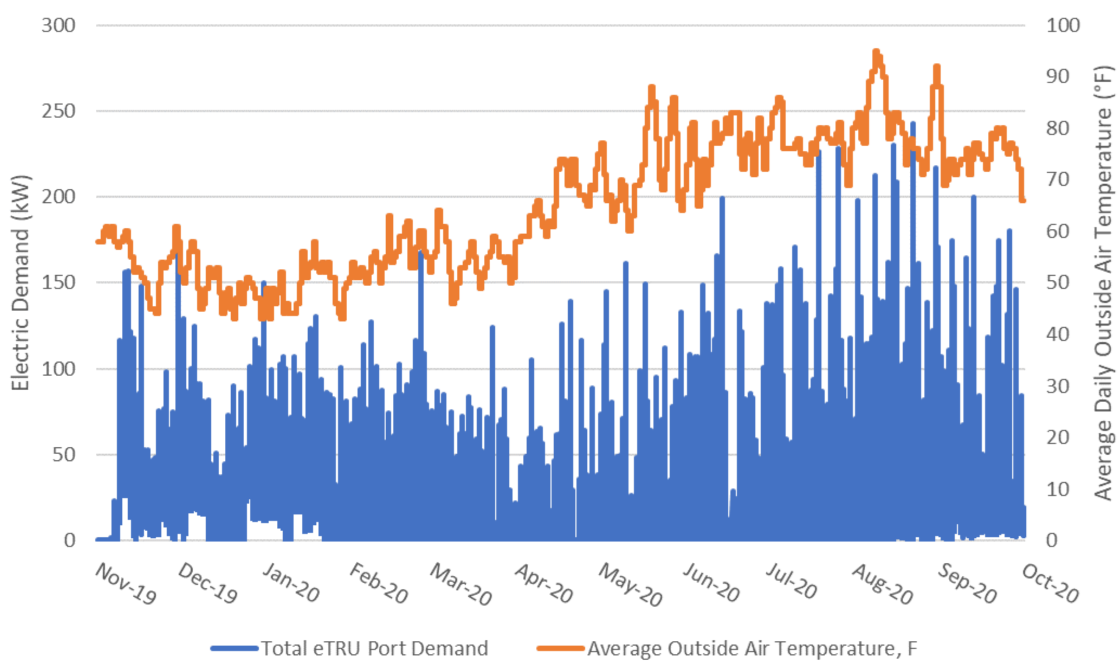
IDLE REDUCTION TECHNOLOGY PILOT

For the Idle Reduction Technology pilot, PG&E partnered with Albertsons to focus this PRP on the eTRU market. Albertsons staff provided data from submeters in 15-minute intervals from early November 2019 through the beginning of October 2020. Chart PG&E-18a summarizes total eTRU port demand for the data collection period compared to average daily outside air temperature. Higher port demand appears to be correlated to high outside air temperatures when refrigeration loads are highest, and compressors are operating at high speeds for longer periods of time. One note is that the maximum metered port demand was higher than

[29] These average energy profiles, which represent only weekdays, do not dip to zero because they average the electric bus charging activity over all the days in the period. Notably, there were a number of operational reasons, such as bus capacity and staffing constraints, that resulted in unique usage patterns across days. Additionally, during Phase 1, to enable the charge management system for some of the buses, the chargers each needed to supply a trickle charge of 1.3 kW to avoid electrical disconnection.

expected for 30-amp breakers, and the Evaluation team for this PRP did not have a secondary data source (such as spot-checked power or a submeter) to compare the metered demand to. Additional data will be required to confirm the peak port demand, but the average metered demand is in line with EPRI's 2015 eTRU market and technology assessment report[30].

Chart PG&E-18a: Albertsons Distribution Center Total eTRU Port Demand



Charts PG&E-18b and PG&E-18c show the average electric demand for each dock and staging area port, respectively, over the data collection period. As shown, port 6 had not been used. Ports with low average electric demand may be used less than others due to inconvenient locations and yard parking procedures. Chart PG&E-14e shows the total eTRU port electric demand for the peak day during the data collection period (August 29, 2020), when the total port demand reached 243 kW.

Chart PG&E-18b: Albertsons Distribution Center Dock Port Average Electric Demand

[30] Market and Technology Assessment of Electric Transport Refrigeration Units, EPRI, 2015: https://www.epri.com/research/products/000000003002006036

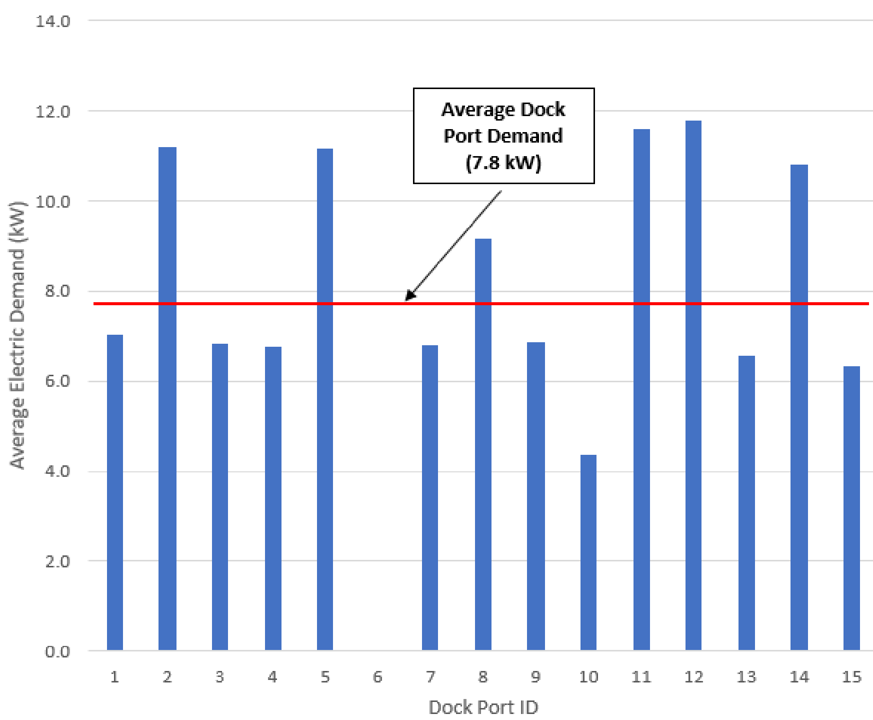


Chart PG&E-18c: Albertsons Distribution Center Staging Area Port Average Electric Demand

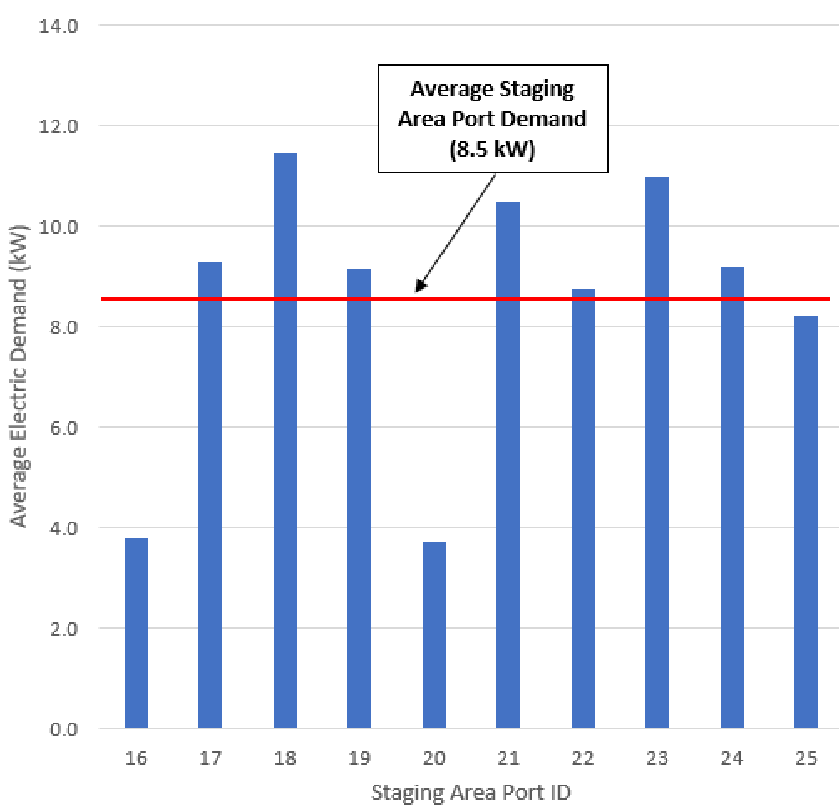
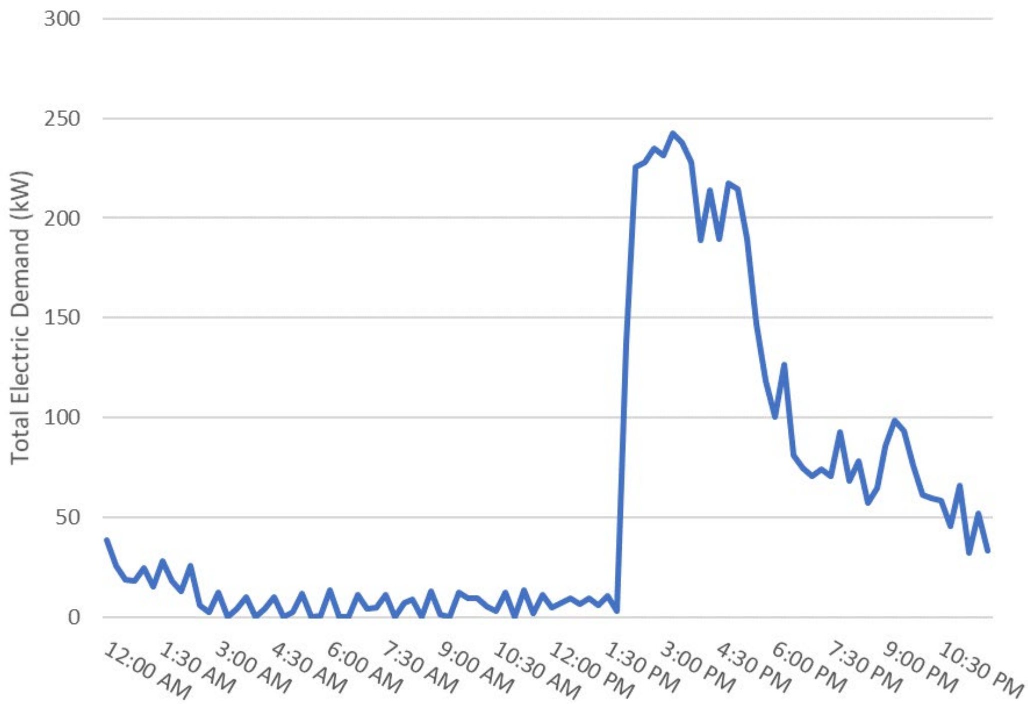


Chart PG&E-18d: Total eTRU Port Demand on Peak Day – August 29, 2020



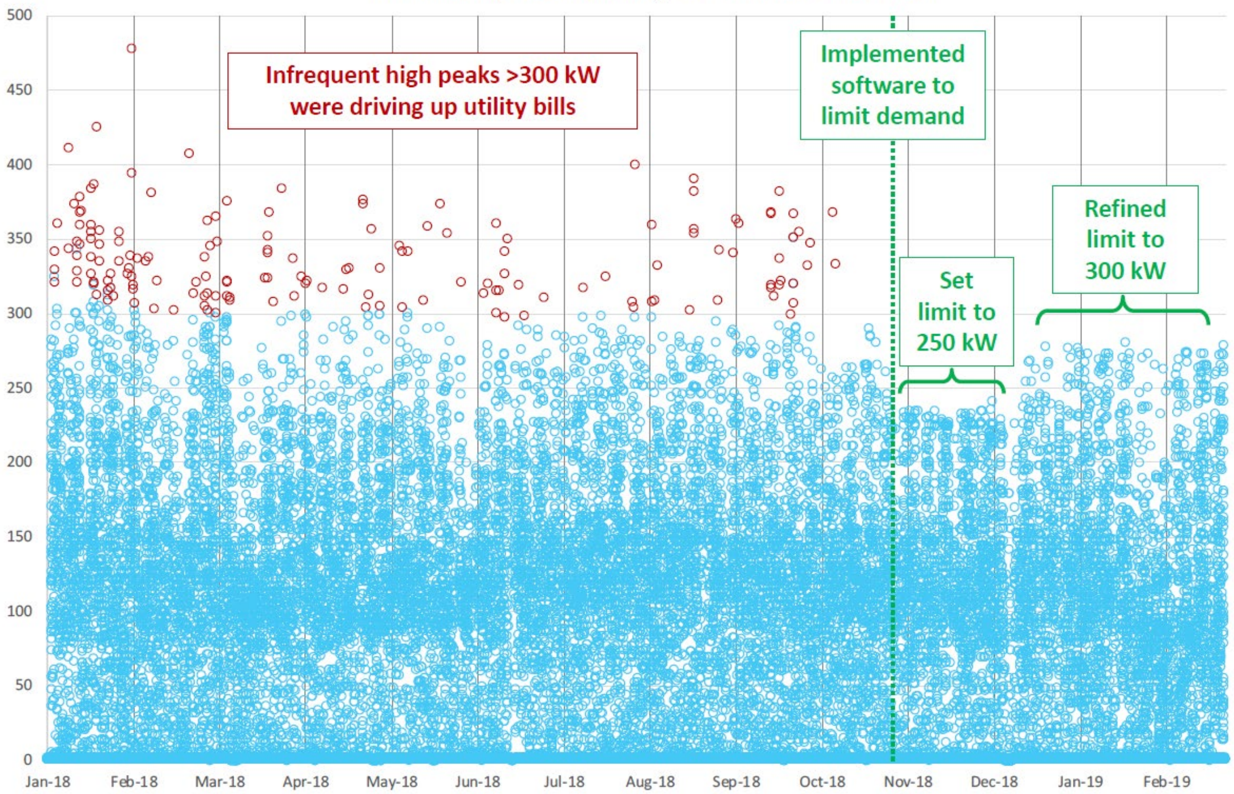
MEDIUM/HEAVY DUTY CUSTOMER FLEET DEMONSTRATION PILOT

For this PRP, PG&E worked with the San Joaquin Regional Transit District (RTD) who operates a MD/HD fleet to develop lessons learned to inform long-term, widespread MD/HD transportation electrification, including the development of the PG&E EV Fleet program. This demonstration helps inform other utilities, fleet operators, site hosts, and customers considering EV deployments. Specifically, the goals of the pilot were to:

- Reduce the TCO using three unique charging models:
    - Overnight charging at the Regional Transportation Center (RTC) depot location using DC fast chargers,
    - Extreme fast charging at a Union Transfer Station (UTS) paired with energy storage, and
    - Extreme fast charging at a Downtown Transit Center (DTC) paired with demand management software,
- Inform how transit agencies can best implement transportation electrification and electrify their fleet, and
- Identify how non-electrification resources could be used to evaluate other opportunities for cost savings and energy management.

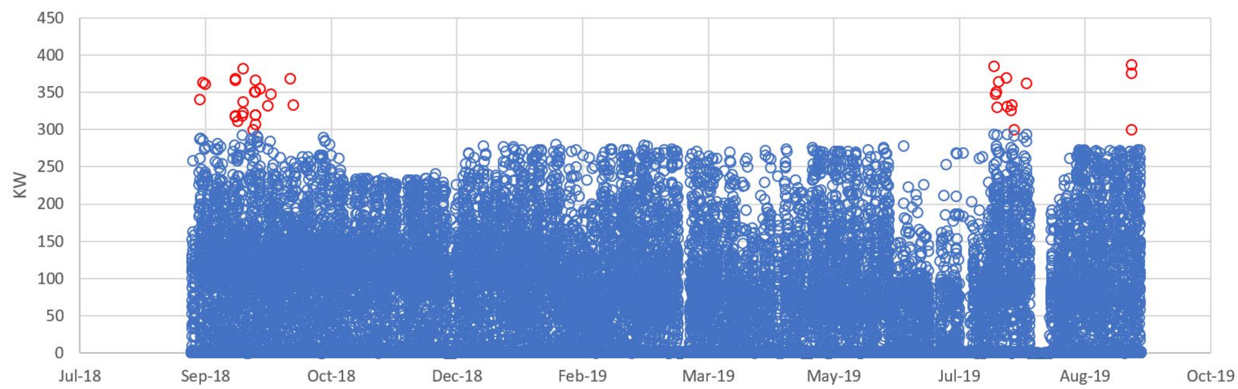
PG&E also planned to use its non-electrification resources (such as energy efficiency, distributed generation, and demand response products and programs, along with rate analysis) to evaluate additional opportunities for energy management and customer bill savings.

Chart PG&E-19a: RTD Daily Demand at DTC by 15-minute Interval



PG&E noted that, prior to this PRP, RTD routinely incurred higher costs per mile for its buses charged via the extreme fast chargers at their transit center. PG&E worked with RTD and a third party to develop a software solution to address this challenge by capping demand. This intervention was effective in reducing costs per mile for those buses, provided that the fleet also maintained a high level of charger utilization. Charts PG&E-19a and 19b show the effectiveness of demand management in the first few months and subsequent six months, respectively. Datapoints highlighted in red are time intervals in which demand exceeded 300 kW. One month after RTD implemented the demand limiting software, it determined that the initial threshold of 250 kW was too restrictive and affected the ability to adequately charge buses for their duties, so it increased the threshold to 300 kW.

Chart PG&E-19b: RTD Demand Plot from September 2018 through August 2019



As shown in Chart PG&E-19b, RTD successfully stayed under its demand management cap from October 2018 to June 2019. It appears it overrode the demand management cap at the transit center in July and September 2019 for operational reasons, resulting in higher costs for those months. Despite the limitations associated with managing bus charging patterns while attempting to maintain maximum utilization of these resources, demand charge savings are clearly documented through RTD's electric bills.

As referenced above, more detailed data from PG&E's TE programs can be found in the quarterly reports to the Program Advisory Council and in the PRP Evaluation Reports to be published simultaneously.

Conclusions and Observations

PG&E

- While the data collected are illustrative of the behaviors of early PEV adopters, one cannot conclude that these behavior patterns will hold as PEV technology continues to mature, charging technology and charging behaviors evolve, and PEVs achieve greater market adoption beyond the early adopter phase. Consequently, data that is sufficiently reliable for policymaking can only be obtained via an appropriately funded and carefully designed study that controls for the above issues.
- There is evidence that, amongst this group of early adopters and for this current composition of vehicles, customers on TOU PEV rates are charging during off-peak periods: single-metered customers tend to use a lower percentage of energy in the on-peak period and a higher percentage in the off-peak period as compared to the residential population;

and the diversified peak for both, single-metered and separately-metered customers, primarily occurs between 12am – 2am – there were some exceptions to this in 2020 where peak hour occurred between 7-9pm, which may have been a result of shelter-in-place impacts.

- On average, the PEV early adopters have a higher maximum demand that must be accommodated by the electric distribution system as compared to the average household without a PEV.
- Although the early adopter PEV customers may have a higher average maximum demand, those customers on the PEV rates tend to hit their maximum demand while non-PEV customers are at their lowest usage. There were some exceptions to this in 2020 possibly due to shelter-in-place orders. Thus, there appears to be a diversity benefit created by the TOU rates. However, from the most local service assessment level perspective (i.e., a single household or set of households serviced by a single transformer), the value of this diversity is limited by the fact that the distribution system must still be prepared to accommodate PEV charging during the peak period since these customers can, and occasionally do, charge during those times.
- While PEV rates for commercial customers – BEV-1 and BEV-2 – may still be recent rate offerings for customers, enrollment has increased steadily, particularly for BEV-1. Utilization among customers has also trended, generally, toward off-peak and super off-peak hours, however there is still some usage in the on-peak hours. Given the irregularity of utilization during 2020 due to shelter-in-place orders and the nascency of these rates, conclusions on results may be premature with utilization data available at this time.
- All of the above conclusions are subject to change as the mix of customers and vehicles changes over time. During the study timeframe, the rapidly changing nature of PEV ownership was clearly evident in the changes that occurred in the mix of customers who own PEVs and types of PEVs available. These changes will need to be considered in ratemaking and cost allocation policymaking. Therefore, California will need to continue to be flexible and adaptable with respect to PEV policies.
- For conclusions and observations from PG&E's TE programs please see the quarterly reports to the Program Advisory Council and in the PRP Evaluation Reports to be published simultaneously.

C. SCE's Load and Customer Behavior Data

This report provides data on load and utilization for customers on both residential and commercial EV specific tariffs from January 2019 to December 2020. Additionally, the report considers some significant changes to SCE's time-of-use (TOU) period definitions, which occurred in March 2019.

During the reporting period, SCE offered two rate schedules (tariffs) for residential customers designed to facilitate the charging of PEVs: (1) TOU-D-PRIME and (2) TOU-EV-1. Both schedules employed price-differentiated time-of-use periods. The TOU-D-PRIME tariff applies to both regular household loads and PEV charging loads recorded with a single meter. The time-of-use periods are designed to accommodate PEV charging requirements but apply to all household loads. The TOU-EV-1 tariff requires a second meter dedicated to measuring the electricity used at the PEV charger and the rates and time-of-use periods only apply to the electricity consumed by the PEV. PEV owners may also opt to remain on their existing tariff, likely Schedule D (domestic rate schedule). Based on the number of PEVs SCE estimates are within its service territory, the majority of PEV owners chose to remain on the domestic rate plan.[31]

The primary focus of this report is on tariffs designed with consideration for PEV charging. For commercial PEV charging, SCE offers three tariffs: TOU-EV-7, TOU-EV-8, and TOU-EV-9, which are applicable exclusively for PEV charging. The following sections report the usage characteristics from January 2019 through December 2020 for residential PEV owners identified on the TOU-D-PRIME and TOU-EV-1 tariffs and all commercial customers on TOU-EV-7, TOU-EV-8, and TOU-EV-9 tariffs. Data for January 2019 through December 2019 is included in this report because it was not provided in the previous annual report.

Previously, SCE reported TOU-D-A/B as the single-meter charging option for residential customers. The TOU-D-A/B tariff closed to new customers on March 1, 2019 and was superseded by the TOU-D-PRIME rate which became effective on the same date. SCE is therefore reporting on TOU-D-PRIME in place of TOU-D-A/B in this analysis. Customers who were served on TOU-D-A/B are eligible to continue receiving service on it until transitioned to an applicable tariff with current TOU periods during SCE's residential TOU default implementation.

SCE designed TOU-D-PRIME tariff to provide an attractive charging option to PEV owners. The TOU-D-PRIME tariff, however, is open to all residential customers with any of these end uses: an electric vehicle, behind-the-meter energy storage, or electric heat pump. This means information on PEV ownership must be obtained separately. Since May 2017, SCE began accepting applications for its Clean Fuel Rebate Program which provides rebates to PEV owners even if they are not the original owner of that PEV. This has provided a significant source of identification of PEV owners, which were included in this analysis as of the first full month following their purchase of the PEV. Additionally, any customers who self-identified as PEV owners with SCE by providing their information through email or contact with SCE's call center

[31] See Attachment 2, SCE Table 1, p. 152.

before December 2018 and currently take service under TOU-D-PRIME were also included in this analysis.

Single-Metered Site Rates

Residential

The TOU-D-PRIME tariff is a single-metered TOU tariff aimed at accommodating PEV charging. TOU-D-PRIME has the same periods as SCE's TOU-D-4-9PM rate plan option, but the PRIME option offers the lowest off-peak rates of all TOU rate plans. The price varies seasonally. As of October 2020, the latest rates within this report period, the lowest rate in the summer season was $0.16/kWh during off-peak hours and in the winter season the lowest rate was $0.15/kWh during super-off-peak hours. The tariff has a Basic Charge of $0.40/meter/day throughout the year.

The TOU periods for this tariff are defined as follows:

TOU-D-PRIME	Weekdays		Weekends and Holidays	
	Summer	Winter	Summer	Winter
On-peak	4 p.m. - 9 p.m.	N/A	N/A	N/A
Mid-peak	N/A	4 p.m. - 9 p.m.	4 p.m. - 9 p.m.	4 p.m. - 9 p.m.
Off-peak	All other hours	9 p.m. - 8 a.m.	All other hours	9 p.m. - 8 a.m.
Super-off-peak	N/A	8 a.m. - 4 p.m.	N/A	8 a.m. - 4 p.m.

Table SCE – 1a represents the price ratios of the latest rates within the reporting period that were effective October 1st, 2020.

Table SCE – 1a: Residential Single-Metered PEV Rate (TOU-D-PRIME) Price Ratios[32]

TOU-D-PRIME	Summer On-peak : Mid-peak : Off-peak	Winter Mid-peak : Off-peak : Super-off-peak
Weekday	2.7 : N/A : 1.0	2.6 : 1.0 : 1.0
Weekend	N/A : 1.9 : 1.0	2.6 : 1.0 : 1.0

[32] *See* https://www.sce.com/wps/portal/home/regulatory/tariff-books.

Separately-Metered PEV Rates

Residential

The TOU-EV-1 rate was designed for residential customers who have a separate meter solely for PEV charging. Therefore, the TOU-EV-1 rate only applies to the customer's PEV charging load. The second meter was provided and installed at no additional cost to the customer, however the home's electrical infrastructure may have needed to be upgraded with a second panel and wiring to the charging location. Any costs related to the changes to the home's electrical infrastructure were the responsibility of the customer. For this rate plan, lower rates apply during off-peak hours of 9:00 p.m. to 12:00 noon, and rates change seasonally. For usage between noon and 9 p.m., rates are higher in summer. The following are the TOU periods for the separately-metered rate:

On-peak	12:00 noon – 9:00 p.m., daily
Off-peak	All other hours.

The TOU-EV-1 tariff was closed to new customers as of March 1st, 2019. Existing customers were, however, permitted to continue taking service on this tariff. On February 1st, 2021, this tariff was temporarily reopened to multifamily accommodations until implementation of SCE's 2021 General Rate Case Phase 2 Decision. This development will not be reflected in this annual report.

The relevant price ratios (effective October 1st, 2020) are reported in the following table, Table SCE – 1b.

Table SCE – 1b: Residential Separately-Metered PEV Rate (TOU-EV-1) Price Ratios

TOU-EV-1	Summer On-peak : Off-peak	Winter On-peak : Off-peak
Daily	3.8 : 1.0	2.1 : 1.0

Commercial

Three rate options (tariffs) are available to commercial customers that separately meter the charging of PEVs. TOU-EV-7, TOU-EV-8, and TOU-EV-9 tariffs are available depending on the expected size of the maximum demand. TOU-EV-7 is applicable to customers with charging demands less than 20 kW; TOU-EV-8 is applicable to customers with charging demands equal to 20 kW but less than 500 kW; and TOU-EV-9 is applicable to customers with charging demands of 500 kW and greater. The former separately-metered commercial PEV rates: TOU-EV-3, TOU-EV-4, and TOU-EV-6, were closed on March 1st, 2019. Customers on these tariffs with outdated

TOU periods, were transitioned to the applicable, current separately-metered PEV tariff on their next billing period.

To facilitate the growth of PEV charging at these sites, these tariffs only have energy rates. They also include a customer charge. All these tariffs have the same TOU periods as our residential TOU-D-PRIME rate option shown in the above section. The prices vary seasonally and between tariffs. Beginning on March 1st, 2024, Facilities Related Demand Charges and Time-related Demand charges will be phased in over five years.

Table SCE – 1c, 1d and 1e represent the price ratios for energy of each commercial PEV rate effective October 1st, 2020. The associated customer charges as of October 1st, 2020 were: $0.397/meter/day for TOU-EV-7, $144.74/meter/month for TOU-EV-8, and $521.25/meter/month for TOU-EV-9.

Table SCE – 1c: Commercial PEV Rate (TOU-EV-7) Price Ratios

TOU-EV-7	Summer On-peak : Mid-peak : Off-peak	Winter Mid-peak : Off-peak : Super-off-peak
Weekday	2.7 : N/A : 1.0	3.6 : 1.6 : 1.0
Weekend	N/A : 2.0 : 1.0	3.6 : 1.6 : 1.0

Table SCE – 1d: Commercial PEV Rate (TOU-EV-8) Price Ratios

TOU-EV-8	Summer On-peak : Mid-peak : Off-peak	Winter Mid-peak : Off-peak : Super-off-peak
Weekday	3.8 : N/A : 1.0	3.8 : 1.7 : 1.0
Weekend	N/A : 2.1 : 1.0	3.8 : 1.7 : 1.0

For customer with demand of 500 kW and above, rates are further differentiated by the service voltage level.

Table SCE – 1e: Commercial PEV Rate (TOU-EV-9) Price Ratios

TOU-EV-9	Summer On-peak : Mid-peak : Off-peak	Winter Mid-peak : Off-peak : Super-off-peak
(Below 2 kV)		
Weekday	3.9 : N/A : 1.0	3.6 : 1.6 : 1.0
Weekend	N/A : 2.1 : 1.0	3.6 : 1.6 : 1.0
(2 kV to 50 kV)		
Weekday	3.9 : N/A : 1.0	3.5 : 1.5 : 1.0
Weekend	N/A : 2.1 : 1.0	3.5 : 1.5 : 1.0
(Above 50 kV)		
Weekday	3.6 : N/A : 1.0	2.6 : 1.4 : 1.0
Weekend	N/A : 1.5 : 1.0	2.6 : 1.4 : 1.0

NEM Program Enrollment

The Net Energy Metering (NEM) tariff provides compensation for customers with distributed generation resources such as photovoltaic solar systems. The energy produced by these systems may be consumed on-site and excess generation is exported to the grid. This reduces the amount of energy purchased from the grid. As shown in Table SCE – 2a, the coincidence of PEV ownership and enrollment in the NEM rate option was 24% as of December 2020 on the current, whole-house TOU-D-PRIME tariff.

Table SCE – 2a: NEM Program Enrollment for Residential Single Metering by Customer Type

Month	NEM Customers with Single Metering	NEM as % Single Metering	NEM as % SF Single Metering	NEM as % MDU Single Metering
Jan. 2019	N/A	N/A	N/A	N/A
Feb. 2019	N/A	N/A	N/A	N/A
Mar. 2019	N/A	N/A	N/A	N/A
Apr. 2019	55	16%	18%	4%
May. 2019	185	17%	19%	5%
Jun. 2019	338	17%	20%	6%
Jul. 2019	497	18%	20%	5%
Aug. 2019	658	18%	21%	6%
Sep. 2019	802	18%	21%	5%
Oct. 2019	950	18%	21%	6%
Nov. 2019	1,119	19%	21%	7%
Dec. 2019	1,235	18%	21%	7%
Jan. 2020	1,396	19%	21%	7%
Feb. 2020	1,603	20%	22%	7%
Mar. 2020	1,810	20%	23%	7%
Apr. 2020	1,967	21%	23%	7%
May. 2020	2,078	21%	24%	8%
Jun. 2020	2,188	21%	24%	8%
Jul. 2020	2,307	22%	25%	8%
Aug. 2020	2,449	22%	25%	8%
Sep. 2020	2,597	23%	25%	8%
Oct. 2020	2,780	23%	26%	8%
Nov. 2020	2,950	23%	26%	8%
Dec. 2020	3,120	24%	27%	8%

Table SCE – 2b: NEM Program Enrollment for Residential Separate Metering

Month	NEM Customers with Separate Metering	NEM as % Separate Metering
Jan. 2019	4	1%
Feb. 2019	4	1%
Mar. 2019	4	0%
Apr. 2019	4	1%
May. 2019	5	1%
Jun. 2019	5	1%
Jul. 2019	5	1%
Aug. 2019	5	1%
Sep. 2019	5	1%
Oct. 2019	5	1%
Nov. 2019	5	1%
Dec. 2019	5	1%
Jan. 2020	5	1%
Feb. 2020	6	1%
Mar. 2020	6	1%
Apr. 2020	6	1%
May. 2020	6	1%
Jun. 2020	7	1%
Jul. 2020	7	1%
Aug. 2020	7	1%
Sep. 2020	7	1%
Oct. 2020	7	1%
Nov. 2020	7	1%
Dec. 2020	7	1%

There is no NEM participation on commercial PEV tariffs TOU-EV-7 or TOU-EV-9. Only a couple TOU-EV-8 customers were enrolled in the NEM program throughout the reporting period.

Number of PEV Time-of-Use Accounts

SCE's residential single-metered rate option is open to all residential customers and therefore it is necessary to independently identify which customers own PEVs. SCE leveraged its Clean Fuel Rewards program, which was funded by Low Carbon Fuel Standard credit revenues, to identify customers with EVs. Prior to 2019, some PEV owners were also identified through the California Air Resources Board's California Clean Vehicle Rebate Project. Additionally, customers previously on the, now closed, TOU-D-TEV tariff were included. This tariff was exclusive to PEV owners. For most customers, the date of PEV acquisition is not known. This report includes any owners of vehicles where the model year of their vehicle is older than the current year. As such, 2019 statistics include any accounts with PEVs from model year 2018 or older, and 2020 statistics include any accounts with PEVs from model year 2019 or older.

TOU-D-PRIME became available to customers in March 2019. Since then, there has been a consistent increase in the number of accounts with PEVs for both single-family and multi-family units as can be seen in Chart SCE – 1. It is not known if this trend reflects growth in the overall market or other factors that may influence the rates of self-identification (e.g. rebate incentives, tarriff changes, propensities to contact the Call Center, utility or industry marketing efforts, new vehicle models with different specifications, etc.). As of December 2020, SCE has identified 12,968 single-metered PEV owners, of which 85 percent were single-family units.

Chart SCE – 1: Residential Single Meter (TOU-D-PRIME) – Number of Accounts by Customer Type at the Beginning of Each Month

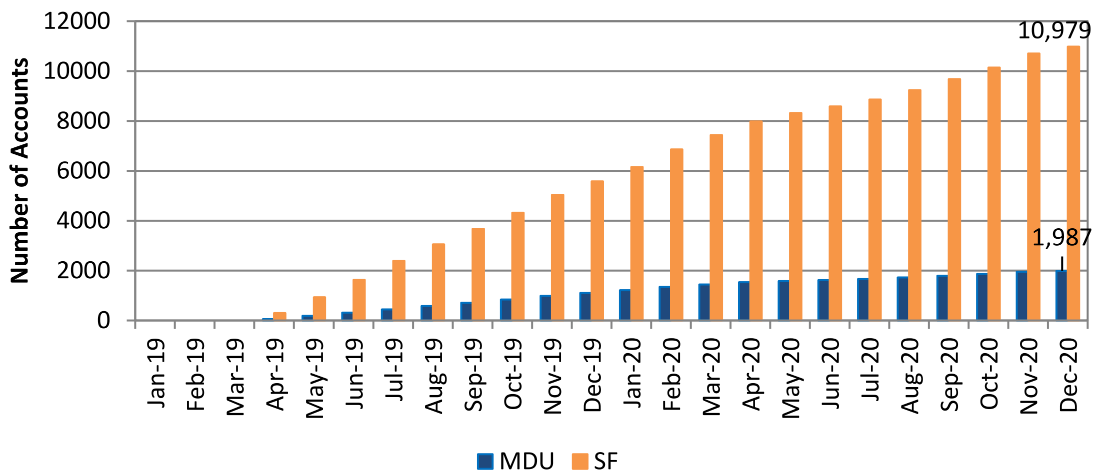


Chart SCE – 2a shows a slight downward trend of separately-metered accounts (TOU-EV-1) over this reporting period but the total remains at 726 as of December 2020. Beginning in March 2019, TOU-EV-1 was closed to new customers. With customers only able to depart this tariff option, the customer account has decreased slightly over time. The number of TOU-EV-1 accounts reported here are only the accounts which register charging during the month. There are some active accounts which persistently have zero usage. This could occur if the location is not a primary residence or if there was a change of ownership and the PEV is no longer present. It could also occur if all the charging is done away from the residence.

Chart SCE – 2a: Residential Separate Meter (TOU-EV-1) – Number of Accounts at the Beginning of Each Month

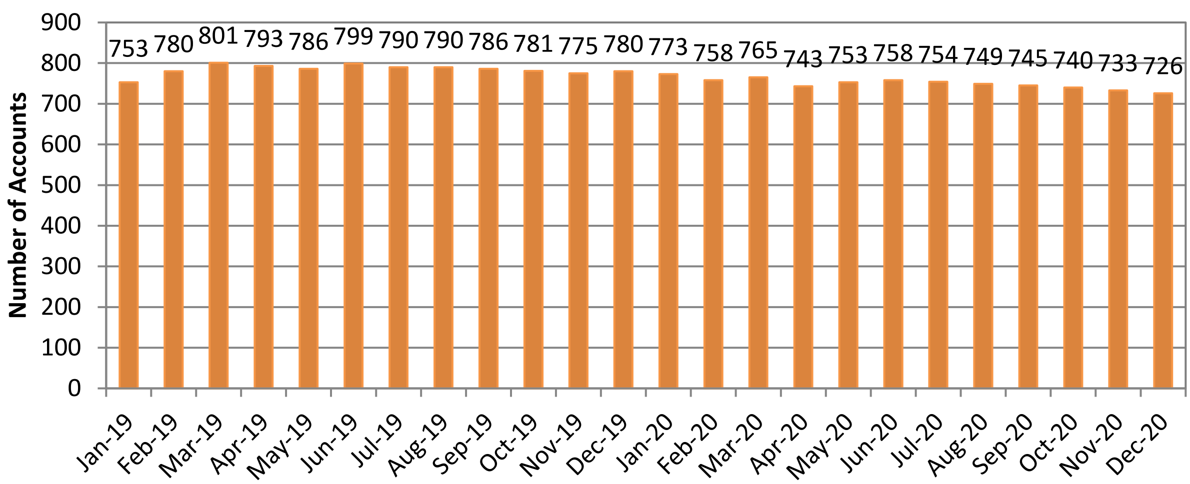
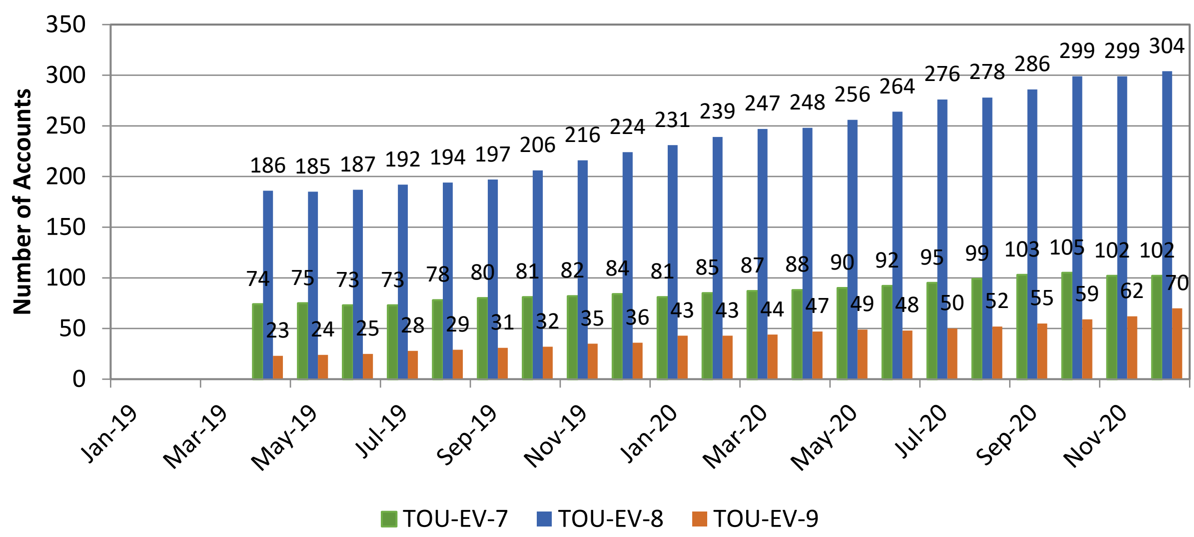


Chart SCE – 2b reflects the steady upward trend of commercial, separately-metered accounts. As of December 2020, there were 102 customers served on TOU-EV-7 tariff, 304 customers were served on TOU-EV-8, and 70 customers were served on TOU-EV-9. Demand for commercial TOU-EV rates has been boosted by SCE PEV programs which invest in PEV charging infrastructure. The growth rate is greater for tariffs with larger PEV charging demand. The growth rate for TOU-EV-8 is larger than the growth rate for TOU-EV-7 and the growth rate on TOU-EV-9 is larger than the growth rate of TOU-EV-8. This may result from PEV charging locations gaining greater utilization, increasing demand, and the customers switching to the applicable rate.

These tariffs were opened March 2019, however, the majority of customers from the retired commerical PEV tariffs were transitioned to the current commercial PEV tariffs in April 2019. Therefore, the period covered in this analysis for commercial tariffs is April 2019 – December 2020. The number of the customers reported here are only the accounts which registered charging during the month. Similar to the case with TOU-EV-1, there are a number of accounts which have zero usage. This might occur when the account is first established but has not yet started charging PEVs or does not have any PEV charging due to various other reasons. For example, a business that was temporarily closed down due to the COVID-19 pandemic may have zero usage.

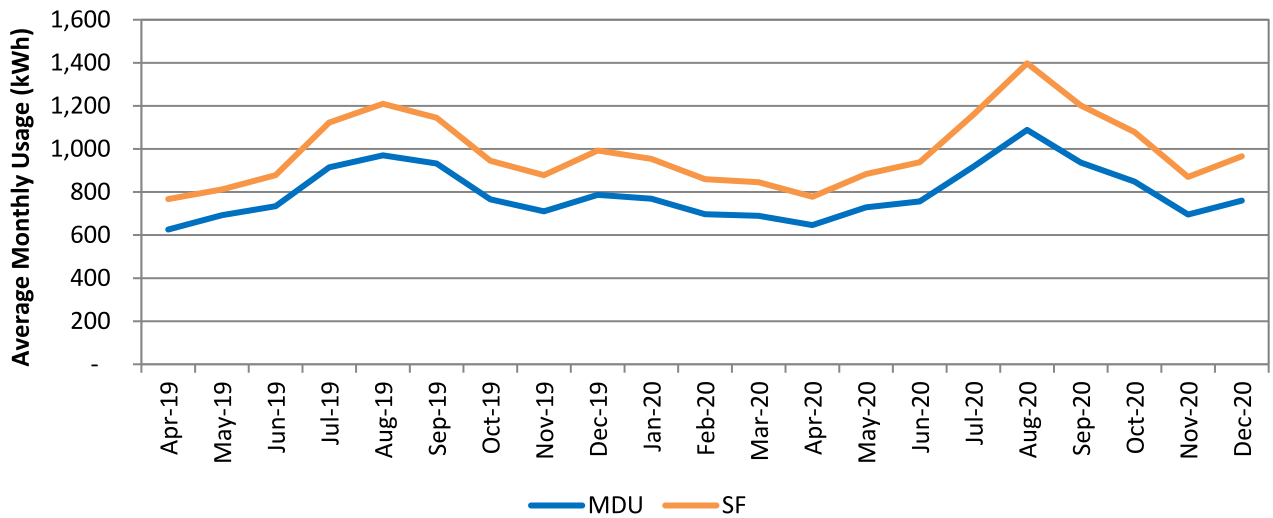
Chart SCE – 2b: Commerical Separate Meter – Number of Accounts at the Beginning of Each Month



Average Monthly Usage for TOU Accounts with a PEV

The average monthly household usage for single-metered households with a PEV shown in Chart SCE – 3 depicts the same seasonal pattern as in previous years as well as very similar usage levels. Single-family dwellings have 24 percent more usage than multi-family units but the same pattern over the course of the year with the lowest usage occuring February through May, and again in November. July to September have the highest usage for single-metered households. This is the typical seasonal behavior of residential households, which is primarily driven by cooling. The greatest average usage during these twenty-one months occurred in August 2020 at 1,398 kWh for SF and at 1,088 kWh for MDU.

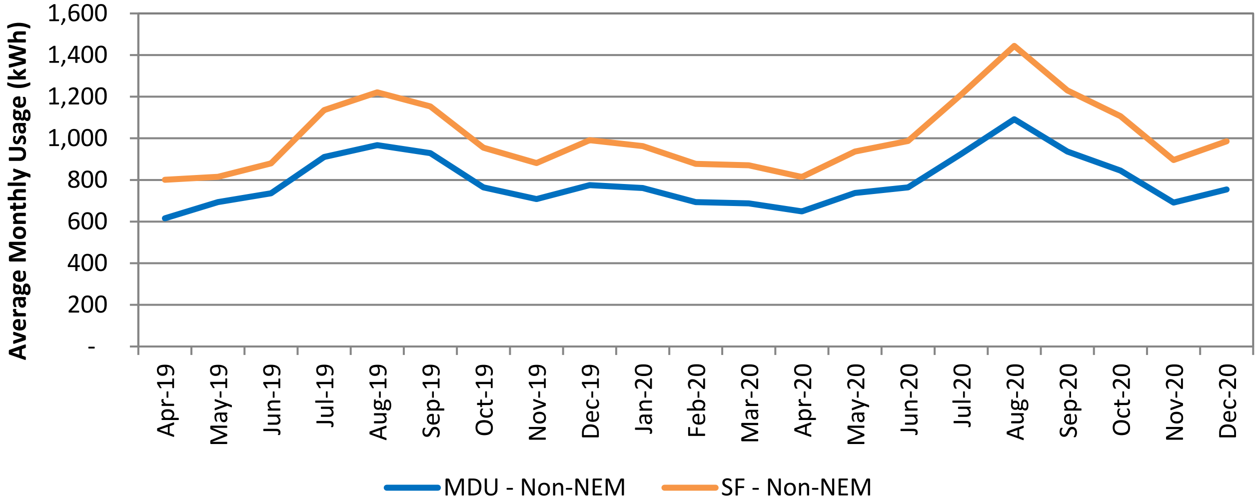
Chart SCE – 3: Residential Single Meter (TOU-D-PRIME) – Average Monthly Usage (kWh) by Customer Type Including NEM



Excluding NEM accounts has very little impact on the average monthly usage of PEV owners, as seen in Chart SCE – 4. The annual monthly usage pattern remains identical to what is shown in Chart SCE – 3. The usage is slightly higher when NEM accounts are excluded, indicating that the NEM households with PEVs take less electricity from the grid than the non-NEM PEV owners. The small impact is in part the result of the relatively small percentage of NEM accounts. Also, the average monthly usage for NEM households is only the energy that is delivered by SCE, not the total consumption or the delivered energy net of exports. If NEM households have higher consumption than non-NEM households, then the balance of their consumption served by SCE might be similar between the two groups. This would also explain why the average monthly usage when NEM households are excluded changes very little.

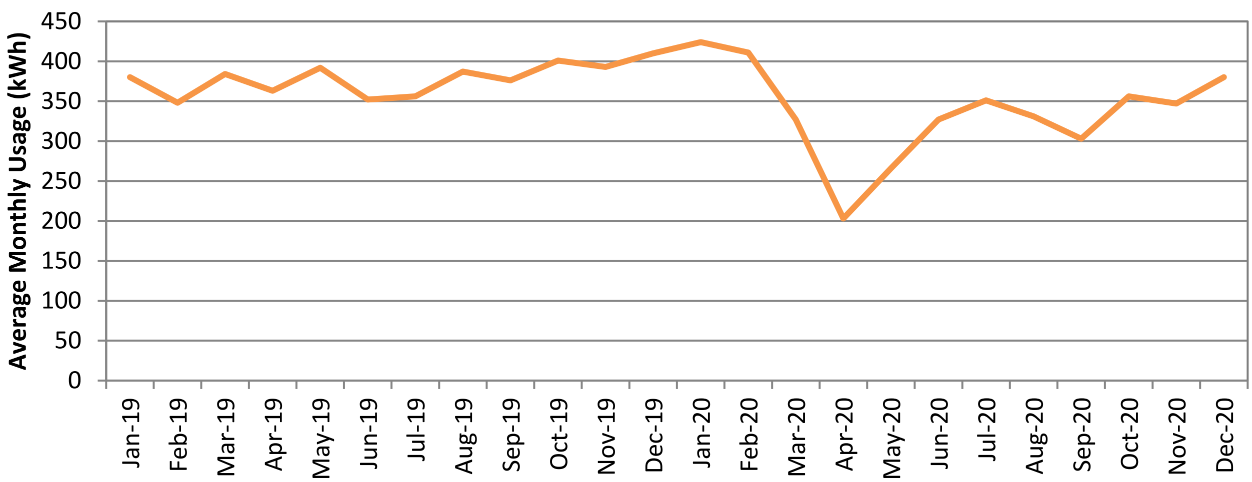
If non-coincident demand were used as an indication of consumption, the non-coincident demands for NEM households with PEVs are higher than the average household. Non-coincident demands for all single-meter PEV owners are presented in Table SCE – 9 and discussed in greater detail below. However, it is worth pointing out that the monthly average non-coincident demands for NEM households range from 7.9 kW to 10.7 kW, indicating that demands for the NEM households with a PEV are about 1.0 kW larger than the average household with a PEV.

Chart SCE – 4: Residential Single Meter (TOU-D-PRIME) – Average Monthly Usage (kWh) by Customer Type Excluding NEM



The average monthly usage displayed in Chart SCE – 5a for separately-metered PEVs ranged from 348 kWh to 410 kWh per month during 2019. The consistent usage observed by the separately-metered PEVs supports the presumption that the seasonal trends seen in the household usage of single-metered PEV owners is not the result of PEV charging. Average monthly usage hit a high of 424 kWh per month in January 2020. In April 2020, the average monthly usage dropped significantly to 200 kWh per month level, largely due the California Stay-at-Home Order that was implemented in March 2020 due to COVID-19. It rebounded sharply to 327 kWh by June and has been recovering slowly since then. In December 2020, the average monthly usage was 380 kWh, the same level as December 2019.

Chart SCE – 5a: Residential Separate Meter (TOU-EV-1) – Average Monthly Usage



The average monthly usage displayed in Chart SCE – 5b for commercial separately-metered TOU-EV-7 ranged from 633 kWh to 744 kWh per month during 2019. The observed average monthly usage was consistent until April 2020, when it declined to and kept under 500 kWh level per month in the following few months, which is most likely driven by the reduced outdoor activities caused by the pandemic. From September to November 2020, the average monthly usage spiked over 1,500 kWh per month, because a high usage account migrated into TOU-EV-7 from TOU-EV-9 given its demand threshold. This account migrated out of TOU-EV-7 in early December 2020 due to an increase in demand. Thus, in December 2020, the average monthly usage dropped back to 619 kWh, the same level as December 2019.

Chart SCE – 5b: Commercial Separate Meter (TOU-EV-7) – Average Monthly Usage

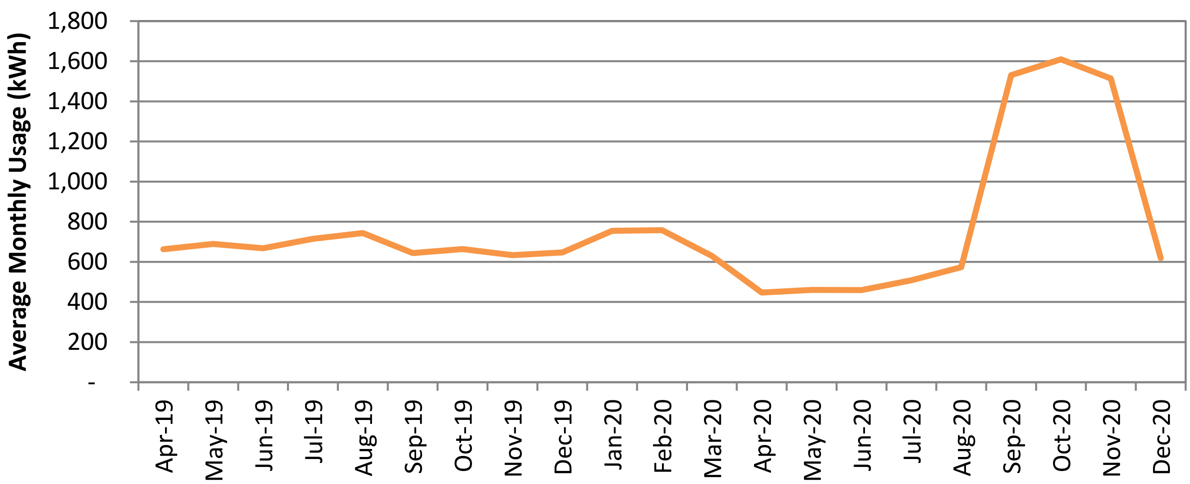
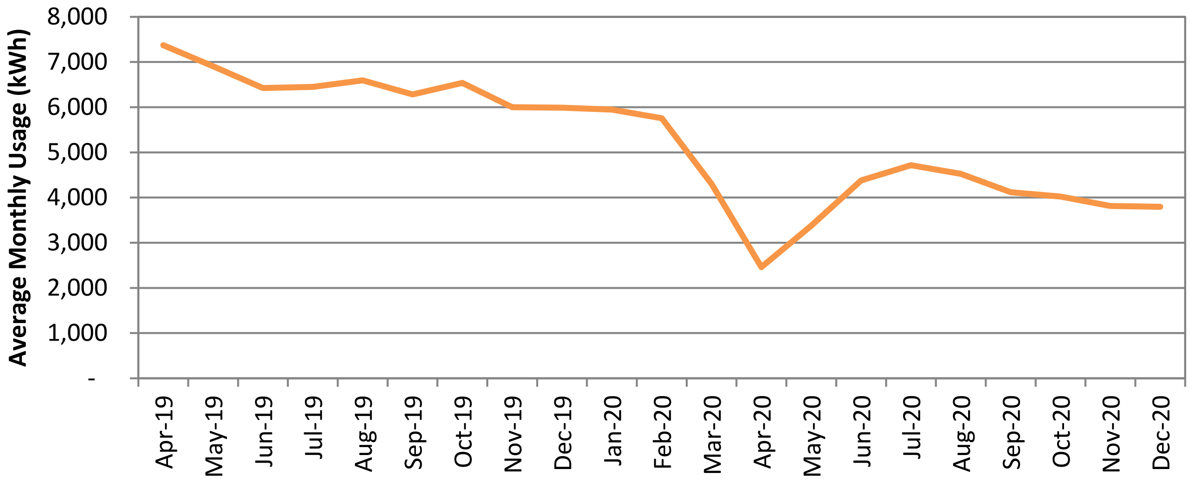


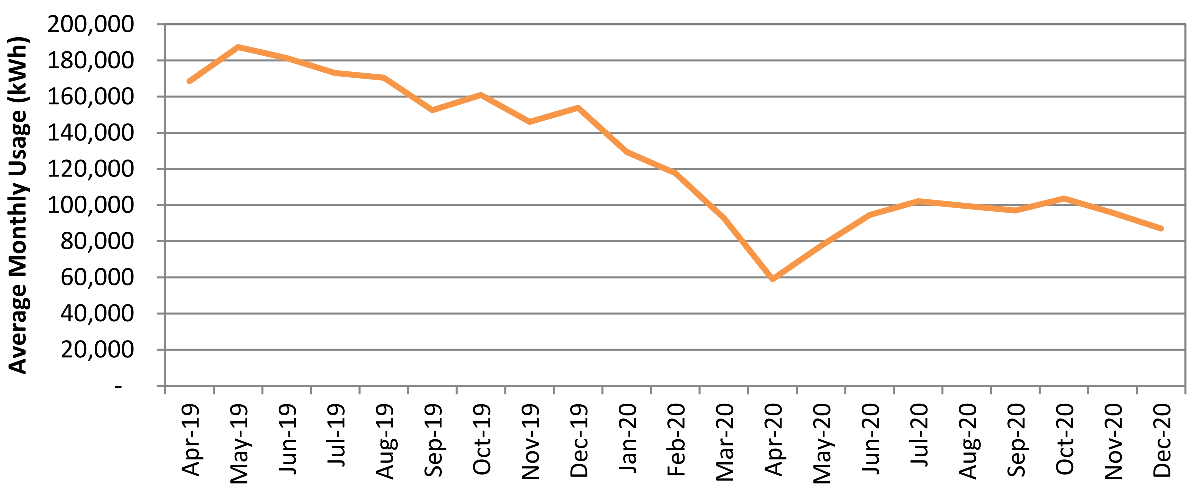
Chart SCE – 5c depicts a declining average monthly usage pattern of commercial separately-metered TOU-EV-8. It hit the highest average monthly usage at 7,372 kWh in April 2019 and remains at 3,797 kWh in December 2020. The average monthly usage is declining as the number of customers increases. This is likely the result of lower utilization on newly installed charging infrastructure. Overtime, there is a variety of smaller customers in terms of the usage who are now being served on TOU-EV-8, which explains the declining trend of average monthly usage. From March to May 2020, the average usage pattern was disrupted and dropped significantly to 2,460 kWh per month, its lowest level, presumably in response to precautionary COVID-19 guidelines and the overall decline in commercial and industrial customers business activity because of the pandemic.

Chart SCE – 5c: Commercial Separate Meter (TOU-EV-8) – Average Monthly Usage



The average monthly usage for commercial, separately-metered TOU-EV-9 shown in Chart SCE-5d, displays a similar declining trend as that for TOU-EV-8. It reached the highest average monthly usage at 187,382 kWh in May 2019, then declined in usage. April 2020 was distinctly lower due to COIVD-19, as mentioned before. Usage remains at 87,002 kWh in December 2020.

Chart SCE – 5d: Commercial Separate Meter (TOU-EV-9) – Average Monthly Usage



Average Usage during Time-of-Use Periods

Some of the subsequent load profiles and usage characteristics will also include the average residential customer as a benchmark for the single-metered PEV customers. This data is derived from SCE's 2019 and 2020 Domestic Rate Group Load Study, which are based on the 2019 and 2020 calendar years respectively.

Tables SCE – 3, 4, 5, and 6 each show the proportion of seasonal usage by time-of-use period for single-metered households. PEV owners have the greatest share of their usage within the off-peak window of the TOU-D-PRIME tariff as shown in Table SCE – 5. In summer 2020, 76 percent of usage by PEV owners without NEM occurred during off-peak hours and in winter 2020, the amount of usage is 50 percent. Both are significantly higher than proportion of usage by the general residential population during off-peak hours at 69 percent and 41 percent, respectively. From Table SCE – 3 and 5, all groups have the lowest proportion of usage occurring in on-peak hours during summer or mid-peak hours during winter.

Table SCE – 3: Residential Single Meter (TOU-D-PRIME) – On-Peak* TOU Distribution

Season	All Residential	Single: Non-NEM	SF: Non-NEM	MDU: Non-NEM	NEM
Summer 2019	21.3%	14.2%	14.2%	13.8%	15.7%
Winter 2019	N/A	N/A	N/A	N/A	N/A
Summer 2020	22.0%	16.7%	16.7%	16.7%	18.2%
Winter 2020	N/A	N/A	N/A	N/A	N/A
* On-peak period is defined as 4:00 p.m. - 9:00 p.m., Summer weekdays.					

Table SCE – 4: Residential Single Meter (TOU-D-PRIME) – Mid-Peak* TOU Distribution

Season	All Residential	Single: Non-NEM	SF: Non-NEM	MDU: Non-NEM	NEM
Summer 2019	9.6%	6.7%	6.7%	6.6%	7.2%
Winter 2019	26.3%	18.5%	18.5%	18.2%	21.3%
Summer 2020	9.2%	7.3%	7.3%	7.2%	8.1%
Winter 2020	27.3%	20.7%	20.8%	20.6%	23.0%
* Mid-peak period is defined as 4:00 p.m. - 9:00 p.m., Weekends/Holidays, all year; and 4:00 p.m. - 9:00 p.m., Winter Weekdays.					

Table SCE – 5: Residential Single Meter (TOU-D-PRIME) – Off-Peak* TOU Distribution

Season	All Residential	Single: Non-NEM	SF: Non-NEM	MDU: Non-NEM	NEM
Summer 2019	69.1%	79.2%	79.1%	79.7%	77.1%
Winter 2019	42.5%	56.3%	56.1%	57.7%	65.7%
Summer 2020	68.8%	76.0%	76.0%	76.1%	73.8%
Winter 2020	40.5%	49.7%	49.6%	50.6%	62.2%
* Off-peak period is defined as all other hours that are not On-peak, Mid-peak, or Super-Off-peak.					

Table SCE – 6: Residential Single Meter (TOU-D-PRIME) – Super-Off-Peak* TOU Distribution

Season	All Residential	Single: Non-NEM	SF: Non-NEM	MDU: Non-NEM	NEM
Summer 2019	N/A	N/A	N/A	N/A	N/A
Winter 2019	31.2%	25.2%	25.4%	24.0%	13.0%
Summer 2020	N/A	N/A	N/A	N/A	N/A
Winter 2020	32.1%	29.5%	29.7%	28.8%	14.7%
* Off-peak period is defined as 8:00 a.m. - 4:00 p.m., Winter daily.					

PEV owners with a separate meter for their vehicle on average charge 88 percent of their usage during the off-peak period in 2019 as shown in Table SCE – 7. Similar results were present in previous reports as well. However, in 2020, off-peak charging has shown a decline to 80 percent level.

Table SCE – 7: Residential Separate Meter (TOU-EV-1) – Usage During Time-of-Use Periods

Season	On-peak	Off-peak
Summer 2019	12.3%	87.7%
Winter 2019	13.3%	86.7%
Summer 2020	22.3%	77.7%
Winter 2020	20.0%	80.0%

Tables SCE – 8a, 8b, and 8c show the proportion of seasonal usage by time-of-use period for each of the commercial, separately-metered rate options. Each table shows a similar usage pattern, in which the greatest share of their usage falls within the lowest rate window. In summer, TOU-EV-7 and TOU-EV-8 charge over 70 percent on average during the off-peak window and TOU-EV-9 charges slightly under 70 percent. In winter, each group of commercial, separately-metered customers charge over 40 percent during the super off-peak window on average. Nonetheless, this does not necessarily lead to the conclusion that customers on commercial PEV rates are responsive to the TOU price signals, because most charging stations and public facilities do not differentiate TOU prices for individual users.

Table SCE – 8a: Commercial Separate Meter (TOU-EV-7) – Usage During Time-of-Use Periods

Season	On-peak	Mid-peak	Off-peak	Super-Off-peak
Summer 2019	19.3%	5.3%	75.4%	N/A
Winter 2019	N/A	24.9%	27.0%	48.0%
Summer 2020	18.0%	7.7%	74.3%	N/A
Winter 2020	N/A	27.2%	24.5%	48.2%

Table SCE – 8b: Commercial Separate Meter (TOU-EV-8) – Usage During Time-of-Use Periods

Season	On-peak	Mid-peak	Off-peak	Super-Off-peak
Summer 2019	17.4%	6.4%	76.2%	N/A
Winter 2019	N/A	24.3%	28.9%	46.9%
Summer 2020	20.0%	7.6%	72.4%	N/A
Winter 2020	N/A	26.4%	27.3%	46.4%

Table SCE – 8c: Commercial Separate Meter (TOU-EV-9) – Usage During Time-of-Use Periods

Season	On-peak	Mid-peak	Off-peak	Super-Off-peak
Summer 2019	21.3%	10.0%	68.7%	N/A
Winter 2019	N/A	29.9%	22.7%	47.4%
Summer 2020	21.3%	9.5%	69.2%	N/A
Winter 2020	N/A	29.8%	22.4%	47.8%

Average Load Profiles - Residential

Average hourly load profiles provide a clear visual depiction of the daily usage patterns. Load profiles are shown on the same chart for single- and multi-family dwellings. Additionally, average hourly load profiles are shown by day type for accounts which self-identified with SCE as PEV owners and remain on the regular domestic, Schedule D, tariff.

The load profiles for single-family and multi-family households with a PEV that opted for the TOU-D-PRIME tariff are shown in Chart SCE – 6. As is typical with residential annual average hourly usage, usage peaks in the evening around 8:00 p.m. Mid-day usage is lower every day, but not quite as low on the weekend as on weekdays. Rather than declining into the morning hours, however, these profiles exhibit a large spike beginning at 10 p.m. and peaking at midnight before tapering until 6:00 a.m. The peak of the weekday spike averages 2.3 kW, 53% greater than the 1.5 kW average usage at 8:00 p.m. The beginning of the spike at 10 p.m. corresponds directly with the off-peak time period of the TOU-D-PRIME tariff and is abnormal for typical residential customers. The peak is likely attributable to PEV charging; however, the observed usage includes all household loads during these hours. Nearly identical behavior is observed with MDU customers in the same Chart SCE – 6, with the exception that the average hourly usage is lower, peaking around 1.8 kW on weekdays. Altogether it appears that the PEV owners who choose a TOU rate for their household and PEV electricity needs are very responsive to the TOU period prices.

Chart SCE – 6: Residential Single Meter (TOU-D-PRIME), Average Hourly Load Profile by Day Type

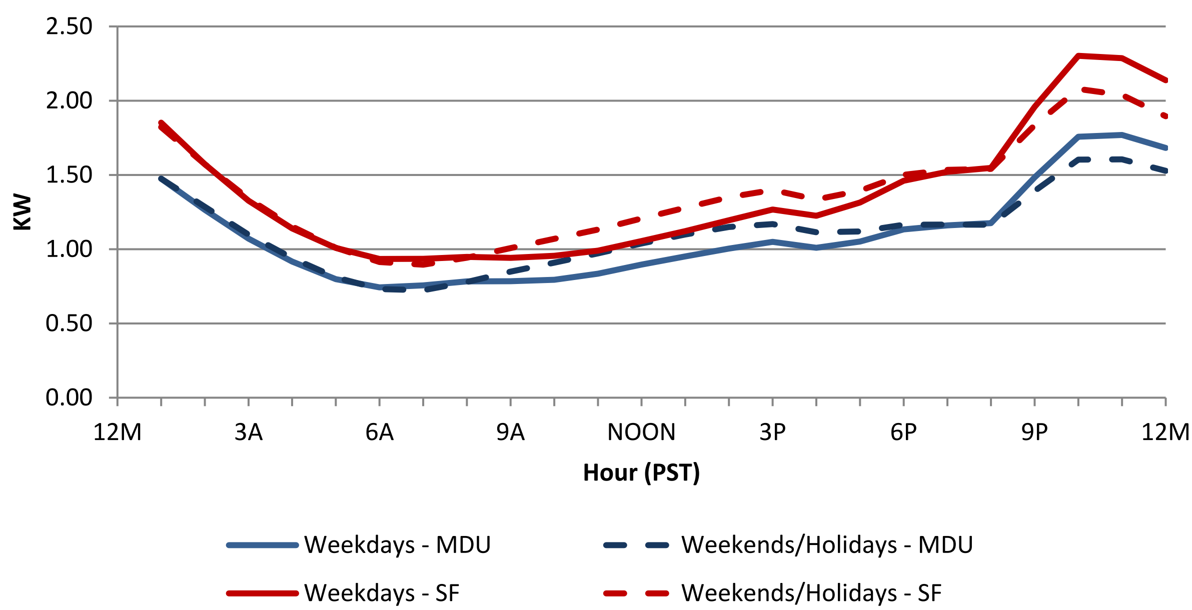


Chart SCE-7 shows that separately-metered PEVs commence charging promptly at the beginning of the off-peak period at 10:00 p.m. After 12:00 a.m., demands begin to taper off as vehicles reach full charges. The highest demand occurs on weekdays and has an average hourly demand of 1.4 kW. Weekend peak demand is around 1.1 kW. Charging during the day between 6:00 a.m. and 8:00 p.m. is very low.

Chart SCE – 7: Residential Separate Meter (TOU-EV-1) - Average Hourly Load Profile by Day Type

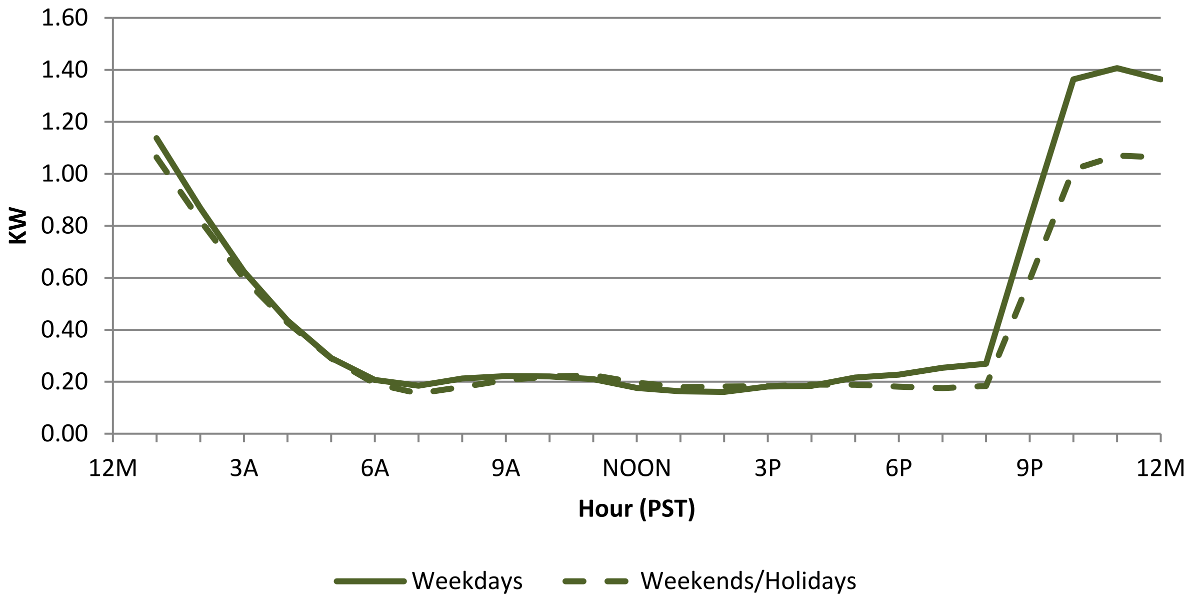
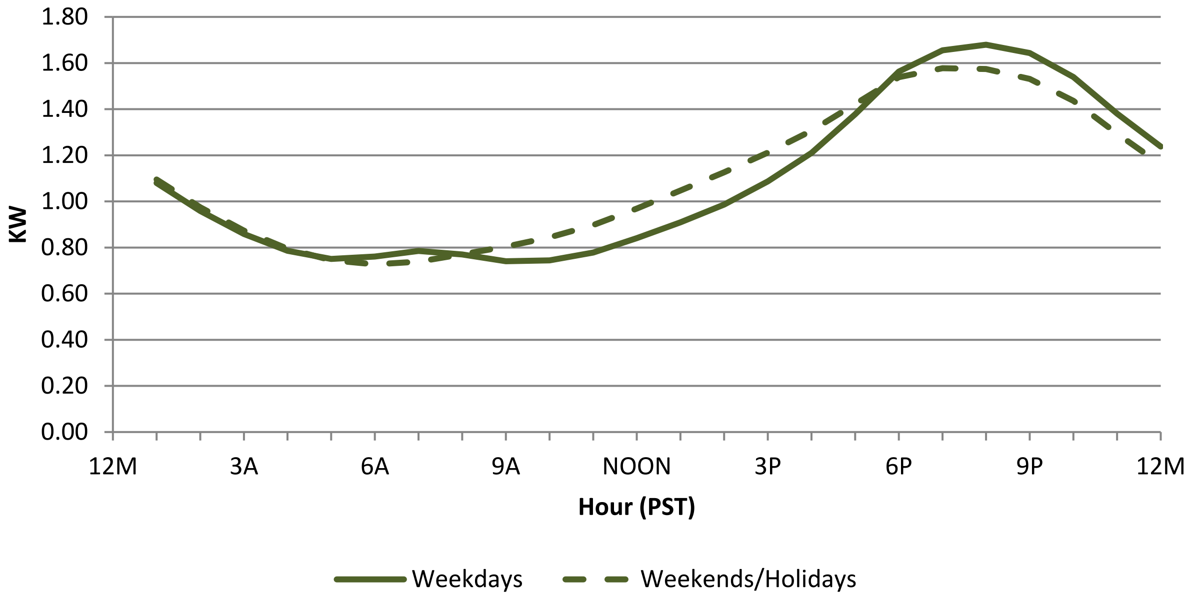


Chart SCE – 8 shows the load profile for a portion of the SF customers who are believed by SCE to own a PEV but choose to remain on the regular, tiered domestic rate. Their daytime demand begins to rise around 10:00 a.m. where it is 0.7 kW on weekdays and increases gradually until it peaks in the evening at 8:00 p.m. at about 1.7 kW on average. Weekend loads are slightly higher during the middle of the day but notably have lower evening peak loads. Late evening loads are also lower presumably due to less PEV charging. As compared to the single-family, single-metered TOU customers in Chart SCE – 6, these non-TOU customers lack the larger peak occurring at midnight.

Chart SCE – 8: Residential Single Meter, SF PEV Owners[33] on a Non-TOU Rate – Average Hourly Load Profile by Day Type



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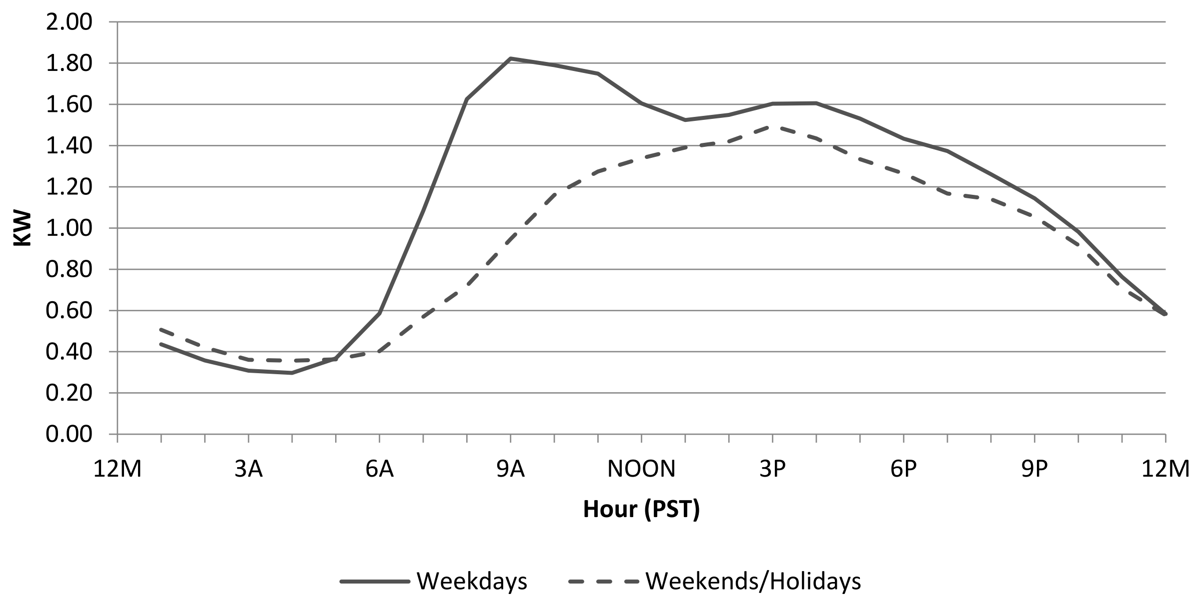
[33] As of December 2020, there were 44,871 accounts, on the Domestic rate schedule (including NEM customers) with load data, which are known to own a PEV.

Average Load Profiles - Commercial

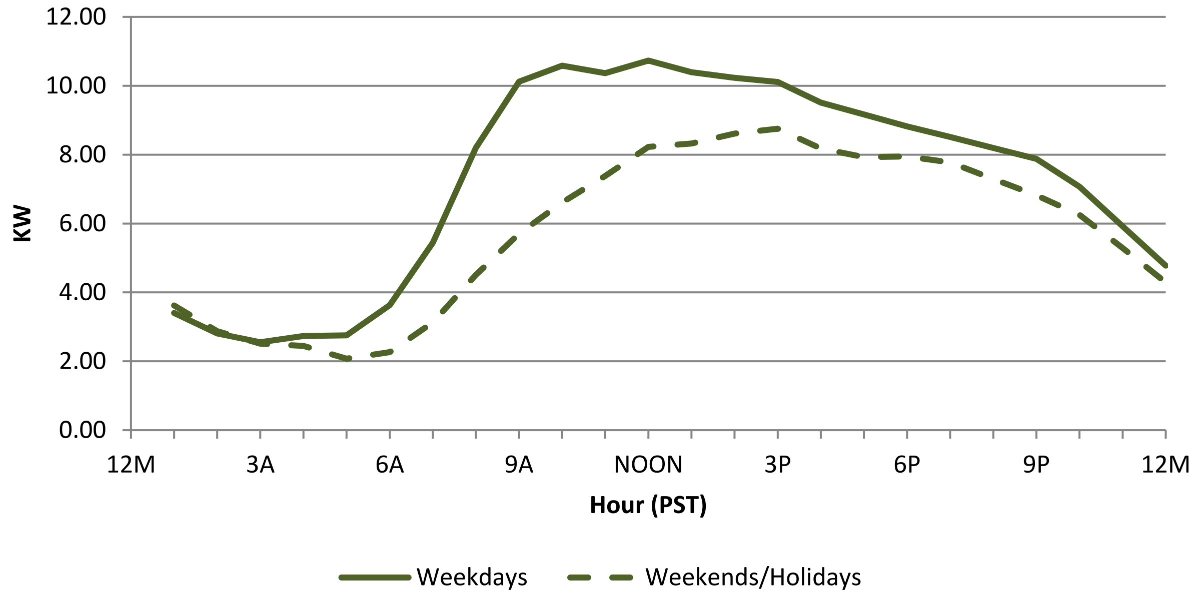
Chart SCE – 9a shows the load profile for commercial separately-metered TOU-EV-7. The average weekday demand begins to rise around 5:00 a.m. where it is 0.4 kW and steeply boosts up to the peak around 9:00 a.m. with an average demand of 1.8 kW. It then drops to 1.5 kW at 1:00 p.m. before a slight rebound to 1.6 kW around 4:00 p.m. After this, it tapers off for the rest of the day. Weekday daily usage is 27 kWh on average, 23 percent more than weekend daily usage. On the other hand, the weekend profile before 5:00 a.m. almost overlaps with the weekday profile, however, unlike the weekday load which spikes in the morning, weekend load displays a shape like a downward parabola from 6:00 a.m. to the midnight with the peak demand of 1.5 kW occurring around 3:00 p.m.

Chart SCE – 9a: Commercial Separate Meter (TOU-EV-7) - Average Hourly Load Profile by Day Type



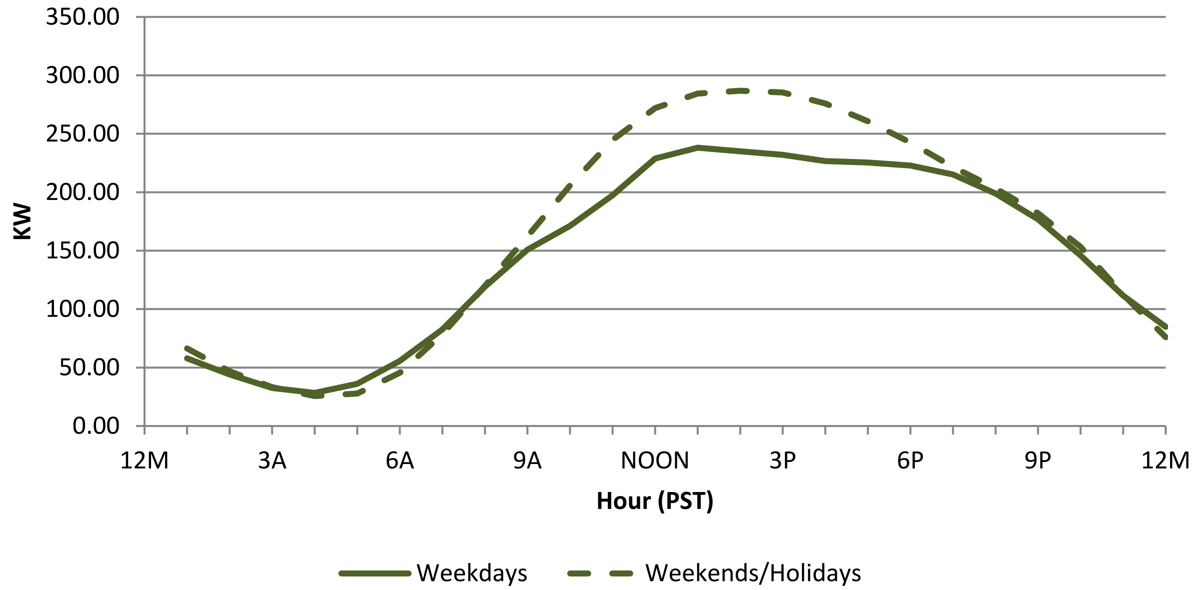
The load profiles for commercial, separately-metered TOU-EV-8, shown in Chart SCE – 9b, have shapes similar to TOU-EV-7. Weekday demand begins to rise from 3 kW at 5:00 a.m. and hits the peak of 11 kW around noontime. From there it tapers off in the rest of the day.

Chart SCE – 9b: Commercial Separate Meter (TOU-EV-8) - Average Hourly Load Profile by Day Type



Unlike the other two commercial PEV tariffs, TOU-EV-9, as shown in Chart SCE – 9c, depicts a similar load shape for both weekdays and weekends, but with a lower weekday usage during mid-day. The weekday peak averages 238 kW around 1:00 p.m., 17 percent lower than the weekend peak of 287 kW at 2:00 p.m. Among commercial PEV tariffs, the TOU-EV-9 charging behavior seems least responsive to the time-of-use period price signals.

Chart SCE – 9c: Commercial Separate Meter (TOU-EV-9) - Average Hourly Load Profile by Day Type



Average Non-Coincident Peak Load

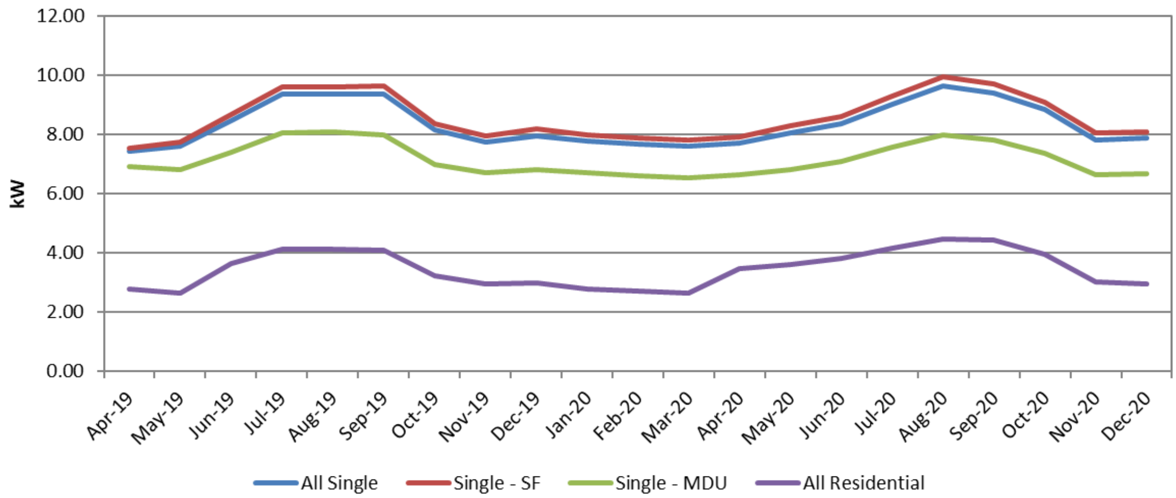
The size and timing of demands on the distribution system as a result of PEV charging is necessary to understand any potential impacts on reliability. This first section will look at the non-coincident peaks for the indvidual accounts with EVs. Subsequently the diversified group peak will be considered.

The average monthly non-coincident peak for all single-metered PEV households of 8.3 kW, as shown in Table SCE – 9, is on average 5.0 kW higher than the residential population as a whole. Chart SCE – 10 shows a seasonal fluctuation in non-coincident demands ranging from a high of 9.6 kW in August 2020 to a low of 7.4 kW in April 2019. The non-coincident demands for single-metered households are about twice as large as the non-coincident demands for general residential population. The general residential population, however, displays a similar seasonal variation in non-coincident demand levels.

Table SCE – 9: Single Meter (TOU-D-PRIME) – Monthly Average Non-Coincident Peak Load (kW)

Month	Residential Pop.	SF Pop.	MDU Pop.	All Single Metering	SF Single Metering	MDU Single Metering
Jan. 2019	2.83	3.07	2.47	N/A	N/A	N/A
Feb. 2019	2.82	3.03	2.50	N/A	N/A	N/A
Mar. 2019	2.70	2.92	2.37	N/A	N/A	N/A
Apr. 2019	2.79	3.11	2.31	7.44	7.54	6.93
May. 2019	2.65	2.93	2.21	7.60	7.76	6.80
Jun. 2019	3.65	4.25	2.76	8.47	8.68	7.39
Jul. 2019	4.11	4.88	2.96	9.35	9.59	8.07
Aug. 2019	4.11	4.87	2.99	9.35	9.59	8.09
Sep. 2019	4.09	4.84	2.98	9.36	9.63	7.98
Oct. 2019	3.22	3.69	2.51	8.14	8.36	6.98
Nov. 2019	2.96	3.28	2.48	7.76	7.96	6.72
Dec. 2019	2.99	3.29	2.53	7.95	8.18	6.83
Jan. 2020	2.78	3.03	2.39	7.78	7.99	6.70
Feb. 2020	2.72	2.97	2.35	7.68	7.89	6.59
Mar. 2020	2.64	2.88	2.28	7.60	7.80	6.54
Apr. 2020	3.48	3.98	2.72	7.71	7.92	6.63
May. 2020	3.62	4.23	2.72	8.04	8.28	6.80
Jun. 2020	3.81	4.46	2.82	8.38	8.62	7.10
Jul. 2020	4.17	4.94	3.03	9.01	9.29	7.56
Aug. 2020	4.47	5.31	3.21	9.63	9.94	8.00
Sep. 2020	4.43	5.26	3.19	9.40	9.70	7.82
Oct. 2020	3.95	4.62	2.96	8.83	9.10	7.37
Nov. 2020	3.01	3.35	2.52	7.82	8.04	6.65
Dec. 2020	2.97	3.29	2.50	7.88	8.10	6.66

Chart SCE – 10: Residential Meter (TOU-D-PRIME) – Monthly Average Non-Coincident Peak Load (kW)

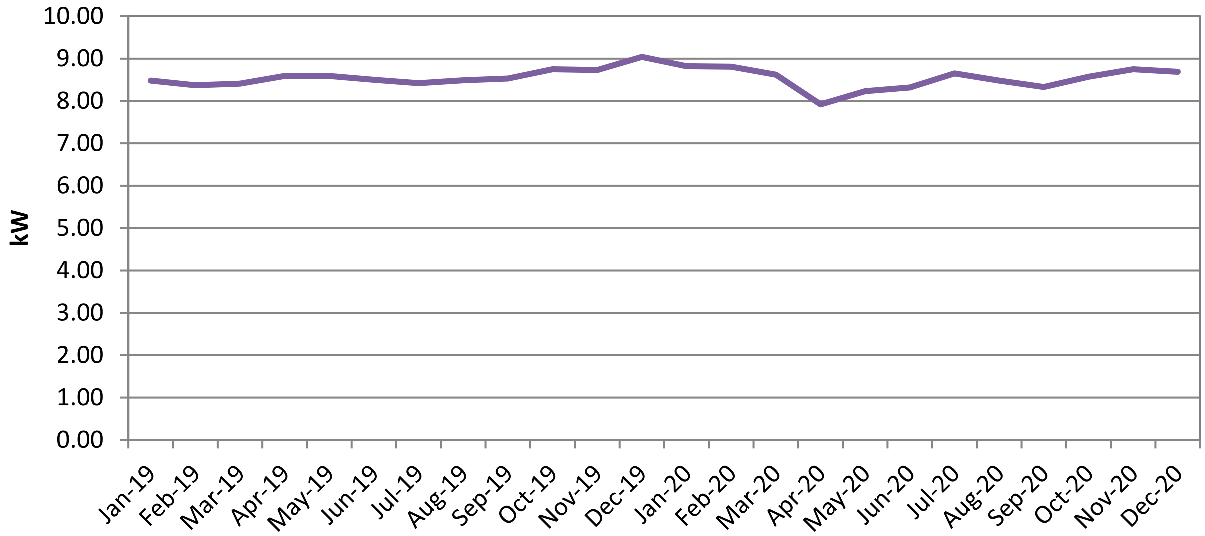


For separately-metered PEV loads, Table SCE – 10 and Chart SCE – 11 show a steady monthly non-coincident demand. The non-coincident demand averaged 8.5 kW for the whole period.

Table SCE – 10: Residential Separate Meter (TOU-EV-1) – Monthly Average Non-Coincident Peak Load (kW)

Month	Separate Metering
Jan. 2019	8.48
Feb. 2019	8.37
Mar. 2019	8.41
Apr. 2019	8.59
May. 2019	8.59
Jun. 2019	8.50
Jul. 2019	8.42
Aug. 2019	8.49
Sep. 2019	8.53
Oct. 2019	8.75
Nov. 2019	8.73
Dec. 2019	9.04
Jan. 2020	8.82
Feb. 2020	8.81
Mar. 2020	8.62
Apr. 2020	7.92
May. 2020	8.23
Jun. 2020	8.32
Jul. 2020	8.65
Aug. 2020	8.48
Sep. 2020	8.33
Oct. 2020	8.57
Nov. 2020	8.75
Dec. 2020	8.69

Chart SCE – 11: Separate Meter (TOU-EV-1) – Monthly Average Non-Coincident Peak Load (kW)

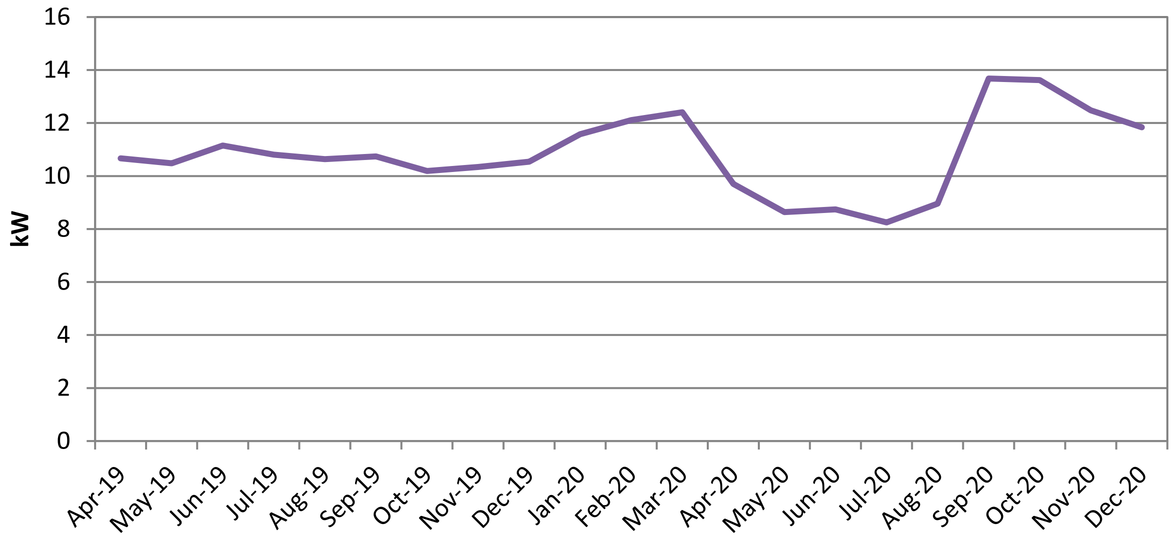


The average monthly non-coincident peak for commercial separately-metered TOU-EV-7, as shown in Chart SCE – 12a, fluctuates between 10 kW and 11 kW in 2019. Similar to the average monthly usage for TOU-EV-7, it dropped significantly in April 2020 and remained at this low level until it rebounded sharply to 14 kW in September 2020. The rebound is attributed to a single high usage account that fell into TOU-EV-7 from a higher rate given its demand threshold. In December 2020, the average monthly non-coincident demand was 12 kW.

Table SCE – 11: Commercial Separate Meters – Monthly Average Non-Coincident Peak Load (kW)

Month	TOU-EV-7	TOU-EV-8	TOU-EV-9
Jan. 2019	N/A	N/A	N/A
Feb. 2019	N/A	N/A	N/A
Mar. 2019	N/A	N/A	N/A
Apr. 2019	10.67	68.02	714.89
May. 2019	10.48	64.15	760.81
Jun. 2019	11.15	62.20	746.39
Jul. 2019	10.81	61.95	705.68
Aug. 2019	10.64	63.19	695.30
Sep. 2019	10.74	64.49	651.13
Oct. 2019	10.19	64.78	656.13
Nov. 2019	10.34	64.78	671.80
Dec. 2019	10.54	65.29	689.99
Jan. 2020	11.58	63.01	593.02
Feb. 2020	12.11	62.95	565.40
Mar. 2020	12.41	56.88	561.62
Apr. 2020	9.70	45.82	399.22
May. 2020	8.64	50.89	470.30
Jun. 2020	8.74	55.88	530.03
Jul. 2020	8.25	55.57	525.85
Aug. 2020	8.96	55.85	496.66
Sep. 2020	13.68	55.11	540.53
Oct. 2020	13.62	53.32	664.29
Nov. 2020	12.48	52.64	580.11
Dec. 2020	11.84	52.77	518.49

Chart SCE – 12a: Commercial Separate Meter (TOU-EV-7) – Monthly Average Non-Coincident Peak Load (kW)



The average monthly non-coincident peak for TOU-EV-8 and TOU-EV-9, shown in Chart SCE – 12b and 12c respectively, also correspond to their average monthly usage pattern however the average monthly demands do not decrease as steeply as average monthly usage. This indicates that load factors are lower for newer accounts. TOU-EV-8 hits the highest average monthly non-coincident peak of 68 kW in April 2019 and declined to 53 kW in December 2020, driven by a number or lower demand accounts served on the tariff. It also exeperienced a dip to 46 kW in April 2020, due to the impact of COVID-19 outbreak. Similarly, TOU-EV-9 hits the highest peak at 761 kW in May 2019 and declined to 518 kW in December 2020, the dip also occurred in April 2020 at 399 kW.

Chart SCE – 12b: Commercial Separate Meter (TOU-EV-8) – Monthly Average Non-Coincident Peak Load (kW)

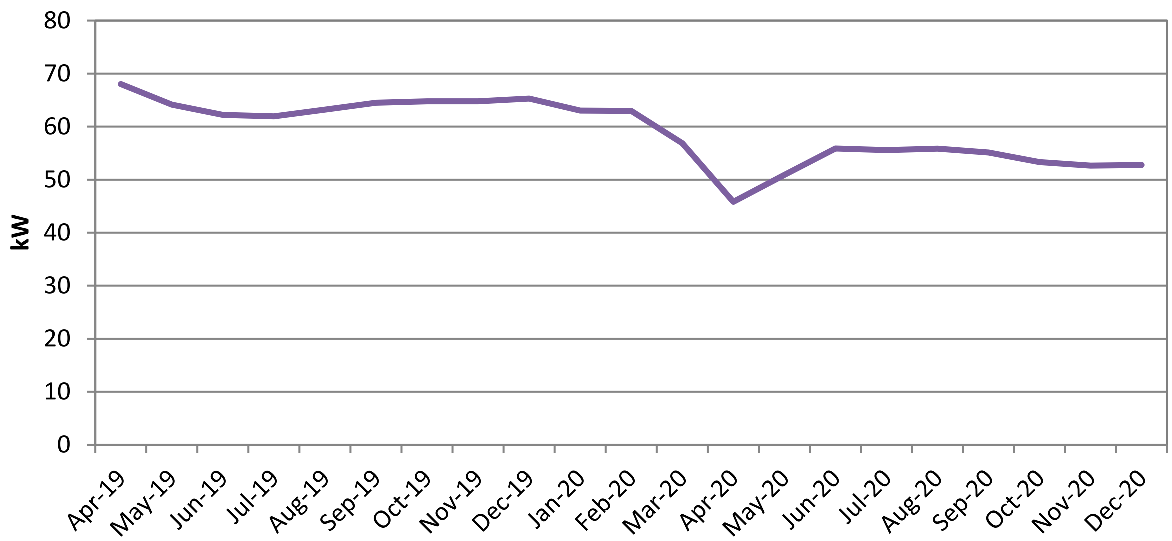
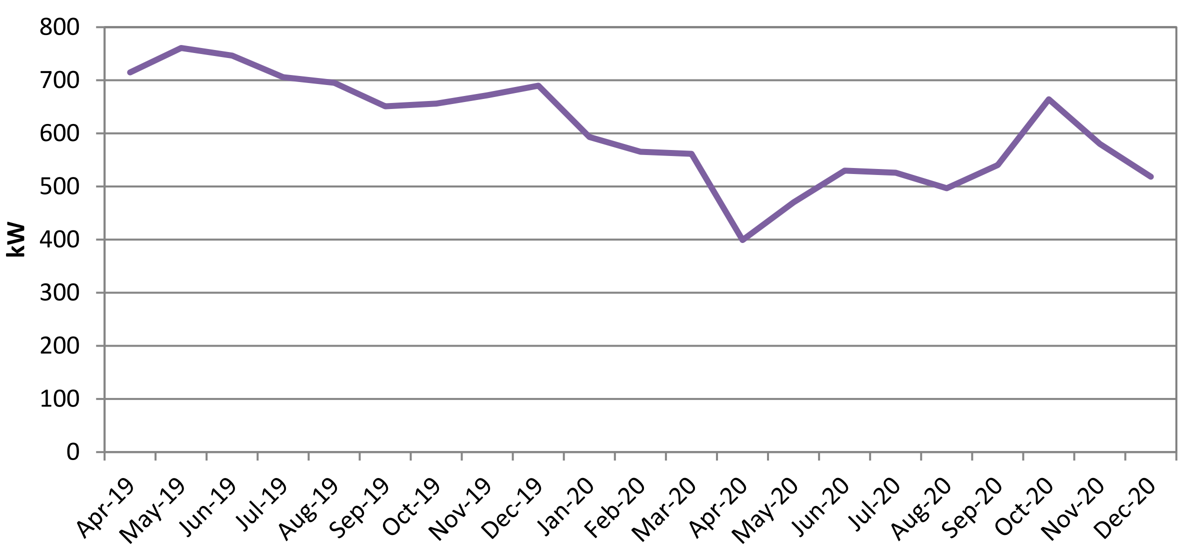


Chart SCE – 12c: Commercial Separate Meter (TOU-EV-9) – Monthly Average Non-Coincident Peak Load (kW)



Average Diversified Peak Load and Timing

In the general population, the hour of residential class peak loads varies throughout the year ranging from roughly 5:00 p.m. in the summer to 7:00 p.m. - 8:00 p.m. in the winter. The magnitude of these peaks also varies, presumably due to different uses. By comparison, the peak load for the single-metered PEV owners is much more consistent month-to-month, averaging 2.3 kW and occurring between 10 p.m. and 11 p.m. The presumed addition of PEV charging loads in the late-night hours augments household loads enough to surpass the demands occurring at other hours of the day.

Table SCE – 12a: Residential Single Meter (TOU-D-PRIME) – Time and Average Diversified Peak Load

Month	Residential Demand (kW)	Hour of Residential Demand	SF Population Demand (kW)	Hour of SF Population Demand	MDU Population Demand (kW)	Hour of MDU Population Demand
Jan. 2019	1.06	20	1.25	20	0.79	20
Feb. 2019	1.07	20	1.23	20	0.83	21
Mar. 2019	0.90	20	1.05	20	0.68	20
Apr. 2019	0.93	20	1.08	20	0.69	20
May. 2019	0.86	20	1.01	20	0.64	20
Jun. 2019	1.71	17	2.12	17	1.11	18
Jul. 2019	2.05	17	2.55	17	1.30	17
Aug. 2019	1.94	16	2.41	16	1.24	17
Sep. 2019	2.11	17	2.62	16	1.37	17
Oct. 2019	1.19	16	1.44	16	0.83	19
Nov. 2019	1.05	13	1.25	13	0.75	13
Dec. 2019	1.10	19	1.32	19	0.78	21
Jan. 2020	0.96	20	1.13	20	0.71	20
Feb. 2020	1.00	21	1.16	21	0.75	20
Mar. 2020	0.91	19	1.07	19	0.68	19
Apr. 2020	1.55	17	1.85	17	1.10	17
May. 2020	1.67	17	2.02	17	1.16	17
Jun. 2020	1.87	17	2.28	17	1.26	17
Jul. 2020	2.27	17	2.83	17	1.45	16
Aug. 2020	2.41	17	2.98	17	1.57	17
Sep. 2020	2.74	16	3.38	16	1.78	16
Oct. 2020	2.12	17	2.62	17	1.41	16
Nov. 2020	1.00	19	1.19	19	0.71	19
Dec. 2020	1.16	19	1.37	19	0.86	19

Table SCE – 12b cont'd: Residential Single Meter (TOU-D-PRIME) – Time and Average Diversified Peak Load

Month	Single Metering Demand (kW)	Hour of Single Metering Demand	SF Single Metering Demand (kW)	Hour of SF Single Metering Demand	MDU Single Metering Demand (kW)	Hour of MDU Single Metering Demand
Jan. 2019	N/A	N/A	N/A	N/A	N/A	N/A
Feb. 2019	N/A	N/A	N/A	N/A	N/A	N/A
Mar. 2019	N/A	N/A	N/A	N/A	N/A	N/A
Apr. 2019	2.25	22	2.28	22	2.03	22
May. 2019	2.21	23	2.28	23	1.90	22
Jun. 2019	2.36	22	2.43	22	1.98	23
Jul. 2019	2.78	22	2.88	22	2.24	22
Aug. 2019	2.92	22	3.03	22	2.32	22
Sep. 2019	2.88	22	2.99	22	2.28	22
Oct. 2019	2.43	22	2.53	22	1.93	22
Nov. 2019	2.19	23	2.27	23	1.79	23
Dec. 2019	2.29	23	2.37	23	1.85	23
Jan. 2020	2.30	23	2.40	23	1.83	23
Feb. 2020	2.27	23	2.36	23	1.83	23
Mar. 2020	1.86	22	1.92	22	1.52	22
Apr. 2020	1.65	22	1.71	22	1.35	22
May. 2020	1.88	22	1.95	22	1.51	22
Jun. 2020	2.14	22	2.22	22	1.69	22
Jul. 2020	2.44	22	2.55	22	1.89	22
Aug. 2020	2.80	22	2.92	22	2.13	22
Sep. 2020	2.57	22	2.67	22	1.99	22
Oct. 2020	2.25	22	2.33	22	1.79	22
Nov. 2020	1.92	23	1.99	23	1.55	23
Dec. 2020	2.02	23	2.09	23	1.61	23

Average monthly diversified peak loads for separately-metered PEVs is 1.5 kW with the peaks occuring between 10:00 p.m. and 11:00 p.m. This indicates a significant amount of diversity in charging as the non-coincident peak loads were 8.5 kW on average. The profiles in Chart SCE – 7 show a rather narrow peak in charging so the most plausible reason that this diversity would arise would be through vehicles not being charged daily at home. The average monthly diversified peak loads dropped under 1.0 kW in April – May 2020, this is consistent with the decreased monthly usage during the same period seen in the Chart SCE – 5a, indicating an effect of California Stay-At-Home Order implemented in March 2020.

Table SCE – 13: Residential Separate Meter (TOU-EV-1) – Time and Average Diversified Peak Load

Month	Separate Metering Demand (kW)	Hour of Separate Metering Demand
Jan. 2019	1.77	23
Feb. 2019	1.77	23
Mar. 2019	1.63	23
Apr. 2019	1.73	22
May. 2019	1.75	22
Jun. 2019	1.61	22
Jul. 2019	1.58	22
Aug. 2019	1.69	22
Sep. 2019	1.73	22
Oct. 2019	1.82	22
Nov. 2019	1.76	23
Dec. 2019	1.68	23
Jan. 2020	1.80	23
Feb. 2020	1.79	23
Mar. 2020	1.21	23
Apr. 2020	0.83	22
May. 2020	0.96	22
Jun. 2020	1.21	22
Jul. 2020	1.20	22
Aug. 2020	1.11	22
Sep. 2020	1.13	22
Oct. 2020	1.25	22
Nov. 2020	1.26	23
Dec. 2020	1.23	23

The average diversified peak loads for commercial TOU-EV-7 in Table SCE – 14, show a nearly identical pattern with its average monthly usage, which was consistent before March 2020, averaging 1.6 kW and peaks occurring the most between 9:00 a.m. to 10:00 a.m. This could be the time when individual PEV owners start charging PEVs at their work facility. The average diversified peak dropped to near 1.0 kW level from April 2020 to August 2020, occurring also around 9:00 a.m. In the last few months of 2020, as discussed in earlier section, a single high usage account migrated into TOU-EV-7 due to its demand threshold, which shifted up the average group diversified peak over 3 kW.

Over this two-year period, there were more smaller accounts joining commercial, separately-metered TOU-EV-8 and TOU-EV-9. Many of them are public facilities and below average usage charging stations, that caused average diversified peak loads to decline. For TOU-EV-8, the highest diversified peak load averaged 15 kW in April 2019. It dropped and remained at 8 kW in

December 2020. The hour of peak loads varies from 9:00 a.m. to 5:00 p.m., with a tendency of shifting from morning to afternoon in 2020. For TOU-EV-9, the highest diversified peak load averages 398 kW in April 2019 and is at 219 kW in December 2020. The peak load for TOU-EV-9 occurs in a narrower window from roughly noon to 3:00 p.m.

Table SCE – 14: Commercial Separate Meter – Time and Average Diversified Peak Load

Month	TOU-EV-7 Demand (kW)	TOU-EV-7 Hour of Demand	TOU-EV-8 Demand (kW)	TOU-EV-8 Hour of Demand	TOU-EV-9 Demand (kW)	TOU-EV-9 Hour of Demand
Jan. 2019	N/A	N/A	N/A	N/A	N/A	N/A
Feb. 2019	N/A	N/A	N/A	N/A	N/A	N/A
Mar. 2019	N/A	N/A	N/A	N/A	N/A	N/A
Apr. 2019	1.68	10	15.13	12	398.12	12
May. 2019	1.62	9	13.89	10	425.50	12
Jun. 2019	1.56	10	12.66	12	406.41	12
Jul. 2019	1.64	10	12.86	12	372.67	13
Aug. 2019	1.64	9	12.78	12	362.95	12
Sep. 2019	1.55	9	12.89	12	339.28	13
Oct. 2019	1.56	9	13.94	9	342.30	12
Nov. 2019	1.42	10	12.69	10	334.63	13
Dec. 2019	1.40	11	12.43	13	344.52	13
Jan. 2020	1.49	12	12.04	10	290.13	14
Feb. 2020	1.82	11	12.70	10	280.59	14
Mar. 2020	1.34	9	8.71	10	202.95	13
Apr. 2020	1.00	9	4.96	13	145.43	15
May. 2020	0.99	9	6.90	15	182.07	15
Jun. 2020	1.14	9	9.95	12	229.24	14
Jul. 2020	1.15	9	10.86	15	234.48	14
Aug. 2020	1.26	9	9.48	12	230.80	13
Sep. 2020	3.44	16	8.71	14	229.63	15
Oct. 2020	3.67	15	8.26	15	241.54	13
Nov. 2020	3.92	16	8.35	17	238.34	13
Dec. 2020	1.40	12	8.17	16	218.78	15

SCE Conclusions and Observations

The statistics and metrics found in this report are based on a sub-population of the total numbers of vehicles sold. As fuel and materials costs fluctuate, vehicle options expand, and technology continues to adapt to customer needs, the future population of owners may have different characteristics and behaviors than the current group. To-date each subsequent report has contained more PEVs but the electric use patterns have remained very consistent.

Residential

- Identification of single-metered TOU and regular domestic accounts of PEV owners relies on self-identification and therefore is subject to selection bias. Furthermore, present ownership of a PEV is not verifiable, thus the extent to which PEV charging load is a component of the metered household load cannot be determined. The reliability of this information therefore cannot be guaranteed.
- SCE was able to utilize participation data from its Clean Fuel Reward program, funded by Low Carbon Fuel Standard credit revenues, to identify a significant number of additional PEV customers.
- A total of 12,968 accounts with a PEV charging under the single-meter TOU-D-PRIME tariff have been identified as of the beginning of December 2020. However, as this rate is open to all residential customers, SCE must rely on self-identification and Clean Fuel Reward Program. Therefore, account growth may not represent the actual numbers of PEVs on the single-metered TOU option or the broader PEV market growth.
- Non-coincident peak demand for the residential separately-metered PEVs was 8.5 kW on average during 2019 and 2020. For comparison, average non-coincident demand was 7.2 kW in the 2014 report, 7.5 kW in the 2015 and 2016 reports, 7.7 kW in the 2017 report, and 8.4 kW in the 2018 report.
- Charging continues to appear concentrated in the off-peak TOU period for single-metered PEV customers. For the separately metered PEVs, off-peak charging remained just under 90 percent in 2019 as in the previous three reports, however in 2020, off-peak charging has shown a decline to 80 percent level.
- There are no appreciable seasonal charging patterns from the identified PEVs but charging appears to be lower on weekends.

Commercial

- There has been considerable customer growth in commercial PEV tariff adoption, driven in part by utility PEV charging infrastructure programs. As of the beginning of December 2020, a total of 476 accounts with PEV charging were under the three commercial PEV tariffs, compared to 283 accounts in April 2019.

- Average monthly usage has declined steadily as more new accounts have been established. The trend is more obvious within TOU-EV-8 and TOU-EV-9. As of December 2020, both average monthly usages remained at nearly half of their highest in April or May 2019.
- Average monthly demand has declined with new customers as well but to a lesser degree than monthly usage. As of December 2020, TOU-EV-8 remained at 78% and TOU-EV-9 remained at 68% of the highest average monthly non-coincident demand occurring in April or May 2019.
- Actions taken to minimize the impact of COVID-19 caused a sharp decrease in EV charging from April 2020 – May 2020.
- Diversified peak demands occurred from 10 a.m. to 1 p.m. in 2019. In 2020, diversified peak demands occur later in the day, during the afternoon from 2 p.m. to 4 p.m. This may be a residual impact from measures implement to reduce COVID-19 health impacts.
- The greatest share or usage occurs in lowest cost window which is off-peak in summer and super off-peak in winter. However, it is not known if this is natural charging behavior or whether customers are responding to the TOU pricing, because most charging stations and public facilities do not differentiate TOU prices for individual users.
- For TOU-EV-7 and TOU-EV-8, charging appears to be higher on weekdays, peaking in the morning whereas TOU-EV-9 accounts charge more on weekends, peaking in the afternoon.

TE Pilots-Programs

- For conclusions and observations, please refer to SCE's Charge Ready Pilot & Bridge Quarterly Reports and the Priority Review Projects (PRP) Final reports published on March 31, 2021.

Transportation Electrification Program Load Data

This report includes load data from SCE's Charge Ready Pilot and Bridge programs only. The report does not capture load information from SCE's Charge Ready Transport or its AB 1082 – Schools and AB 1083 Parks and Beaches programs, as the sites participating in these programs were generally still in the assessment, design, development and construction phases during 2020 and had less than 15 customers.

Average Monthly Usage (kWh) per port

The graphs in Chart SCE – 15a and 15b provide the average monthly usage per port for SCE's Charge Ready Pilot & Bridge program in 2019 and 2020. Ninety-three percent (1,209) of Charge Ready Pilot ports were completed by October 2019. Whereas only 5 percent (70 ports) of Charge Ready Bridge program ports were completed at the end of 2019 and 93 percent (1,349 ports) were completed at the end of 2020. The maturity of the Pilot projects show consistent growth in the usage per port. The peak total usage per port occurs in the month of October 2019 for all segments, with Workplace peaking at 284 kWh. A decrease in usage per port occurs at the end of the 2019. This is likely attributed to an increase in newly installed charging ports in November and December 2019.

Chart SCE – 15a: Charge Ready Pilot & Bridge Average Monthly Usage (kWh) by Port (2019)

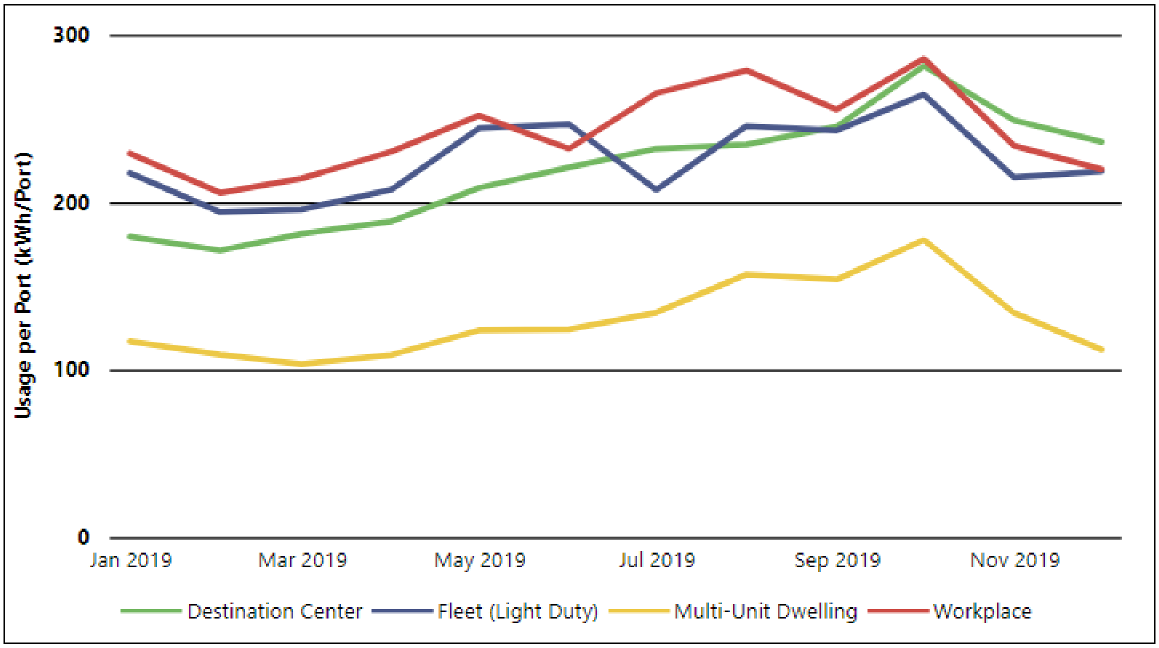
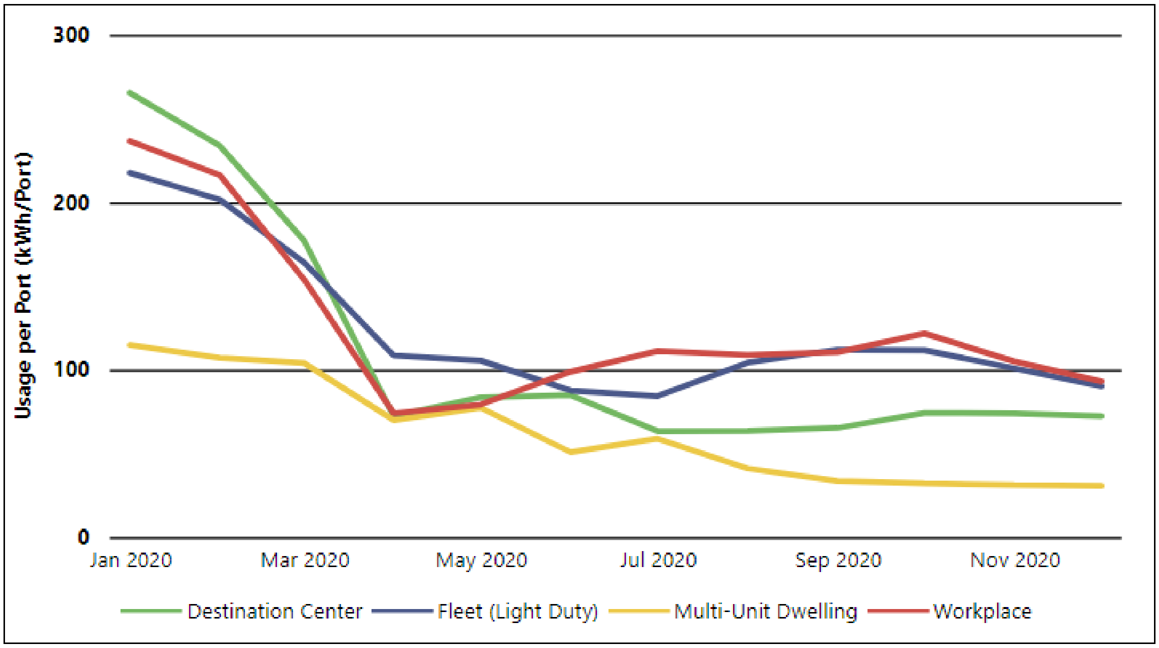


Chart SCE-15b provides the total monthly usage per port for 2020 and shows the monthly usage per port peaking in January, across all segments. Destination Centers saw the highest utilization per port (265 kWh) compared to the rest of the segments. However, the other segments also peak in January with Workplace at 237 kWh, Fleet (light-duty) at 217 kWh, and Multi-Unit Dwelling at 115 kWh. Previously Workplaces would have shown stronger utilization than the other segments; however, it had the greatest number of charging stations installed across the segments, which resulted in a decrease in the average utilization across the ports. Further, there was a significant impact on usage among all segments due to COVID-19. The largest decrease occurred in the month of April. While the monthly kWh usage per port decreased, total monthly usage has steadily increased since May. Additionally, a majority of Bridge projects (1,349 Ports) were completed in 2020, which resulted in a lower total usage per port compared to 2019.

Chart SCE – 15b: Charge Ready Pilot & Bridge Average Monthly Usage (kWh) by Port (2020)



Average Hourly Load profile (kWh) by Port

SCE's hourly load graphs, for the TE pilot-programs, reflect the load that is used for the hour beginning (i.e., load generated at 12:15 AM, 12:30 AM, or 12:45 AM will be identified as 12 AM). This approach may vary from the approach used by the other IOUs.

In 2019, the average weekday hourly load profile by port shows Workplace and Destination Centers having a peak average usage per port at 9AM, while Fleet (Light-duty) peaks at 7PM, and Multi-Unit Dwelling peaks from 7PM to 10PM. Chart SCE -16a displays the average weekday hourly load profile by port for the Charge Ready Pilot and Bridge program in 2019 by segment.

Additionally, Chart SCE – 16b displays the average weekend hourly load profile by port for 2019 by segment. The Fleet (Light-Duty) has the largest peak at 7PM similar to weekdays. The peak for Destination Center is shifted slightly more toward the early afternoon hours of 2PM when compared to the weekday load profile. Multi-Unit Dwelling also peaks later on weekends at 10PM. Workplace charging is much lower on weekends and the shape is flatter in comparison with weekdays.

Chart SCE – 16a: Charge Ready Pilot & Bridge Average Weekday Hourly Load Profile (kWh) by Port (2019)

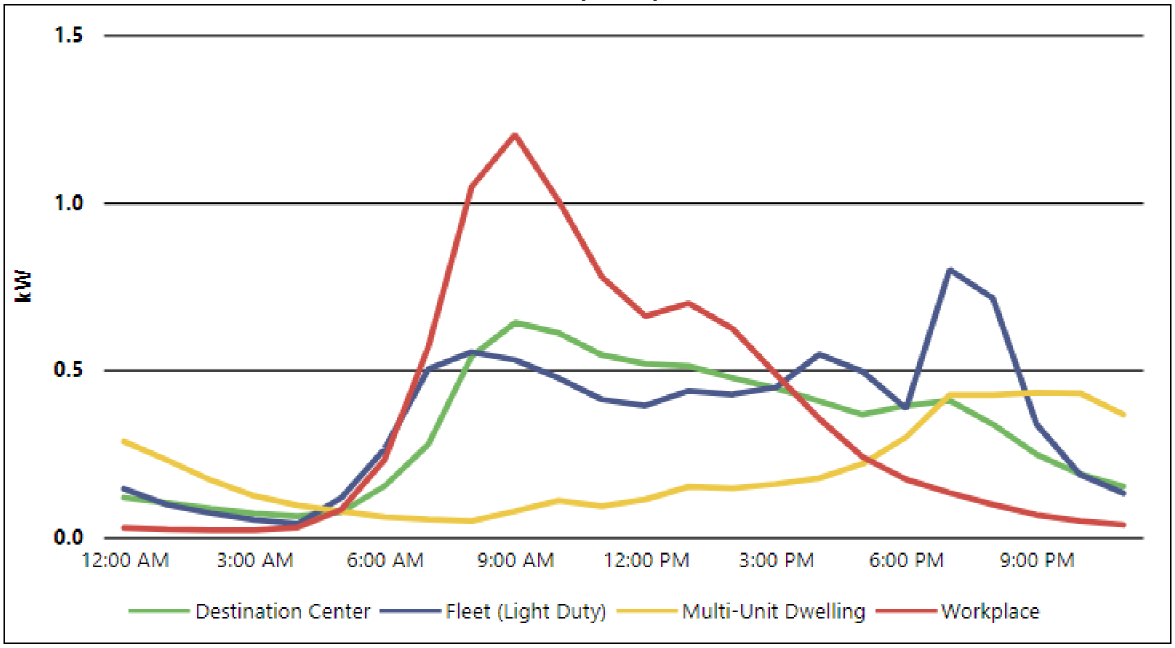


Chart SCE – 16b: Charge Ready Pilot & Bridge Average Weekend Hourly Load Profile (kWh) by Port (2019)

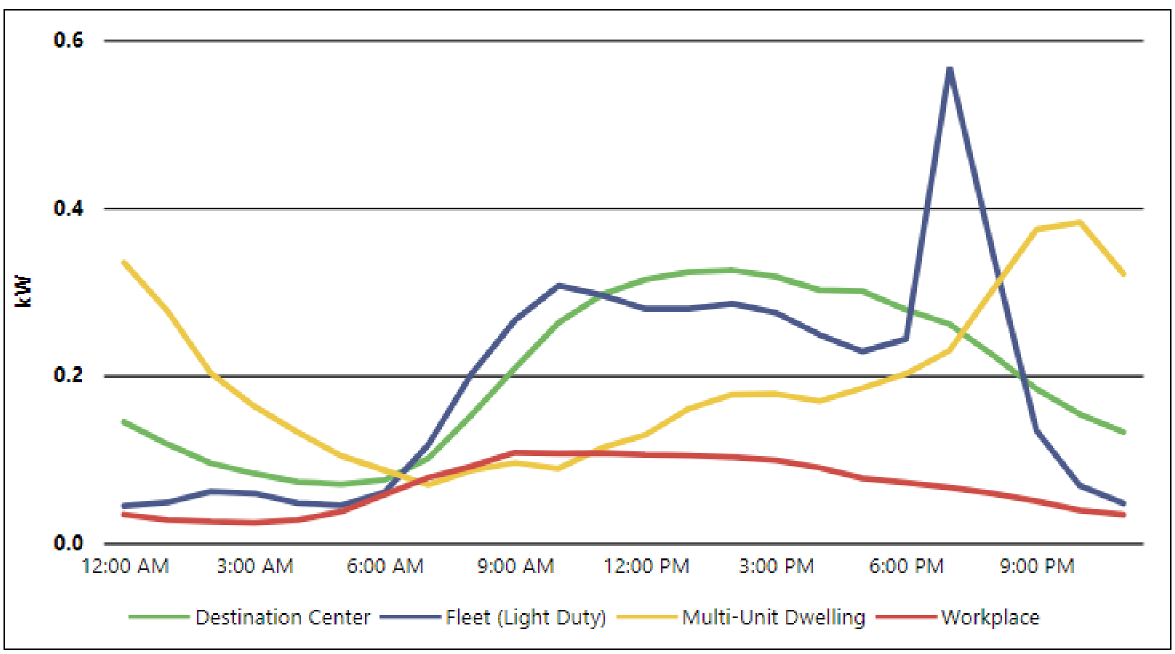


Chart SCE 16c and 16d examine both average weekday and weekend hourly load profile by port for 2020. SCE attributes impacts to utilization across the segments in part to COVID-19.

Average usage per port is much lower in 2020, however the load shapes for both weekend and weekday are very similar to 2019. Another factor impacting utilization, was the increase in the total number of ports completed in 2020. Specifically, a majority of Bridge projects were completed in 2020, resulting in a lower average hourly usage per port in comparison to 2019.

Chart SCE – 16c: Charge Ready Pilot & Bridge Average Weekday Hourly Load Profile (kWh) by Port (2020)

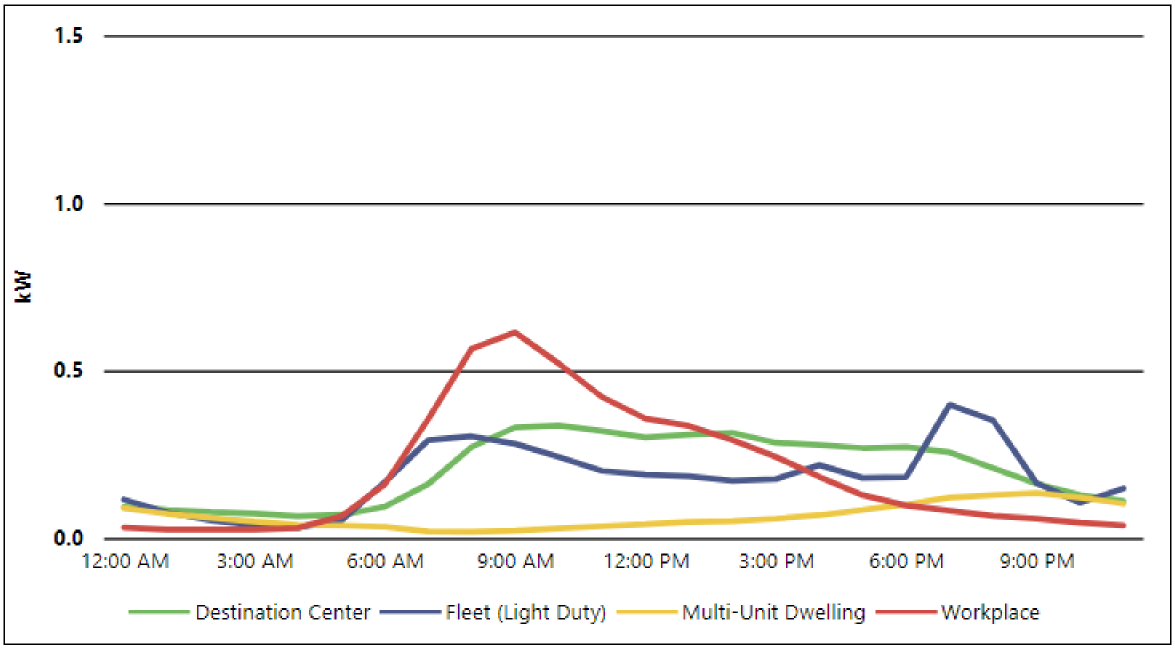
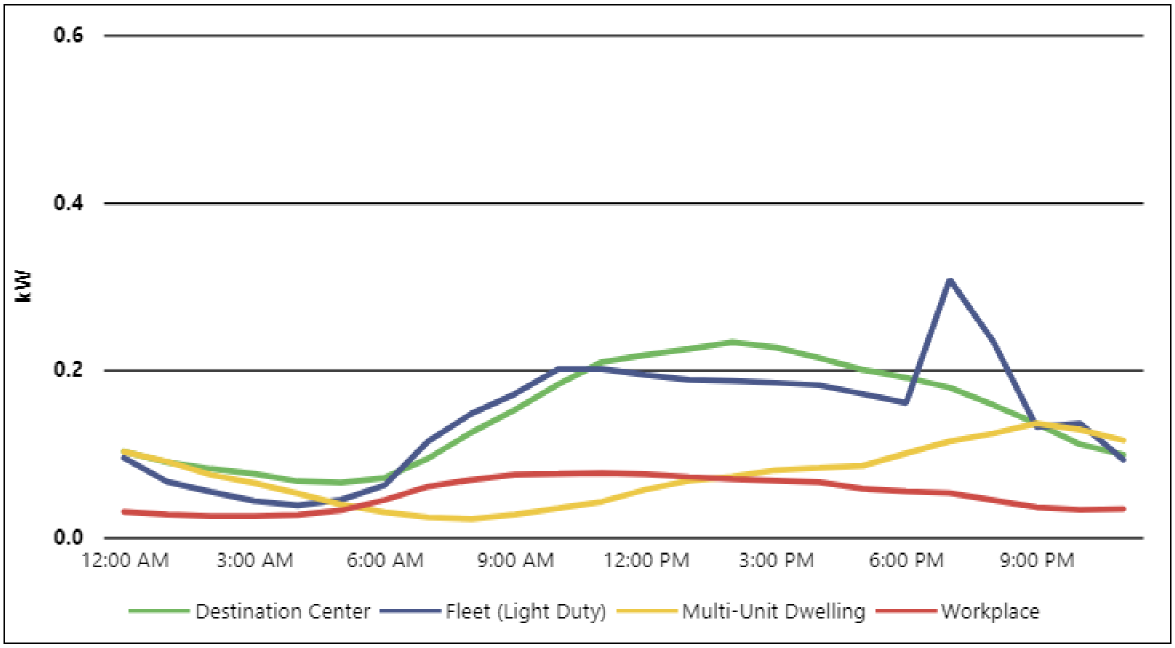


Chart SCE – 16d: Charge Ready Pilot & Bridge Average Weekend Hourly Load Profile (kWh) by Port (2020)



D. SDG&E's Load and Customer Behavior Data

Load and utilization across SDG&E's EV-specific rates and Transportation Electrification Programs are reported in the following sections. The study period covers the full calendar years of 2019 and 2020. SDG&E's rates during the study period included residential EV rates only. The residential rates include SDG&E's Single Metered Rate (EV-TOU) and Separately Metered Rates (EV-TOU-2, EV-TOU-2 (GF), and EV-TOU-5).

SDG&E has no commercial EV rates in the 2019-2020 reporting time period. The EV-HP commercial EV rate was recently approved and will be reflected in subsequent reports as customers sign up for that rate. Additionally, utilization and load data for light duty infrastructure installed as part of SDG&E's Transportation Electrification Programs is reported for both calendar years. Utilization is mostly from charging infrastructure installed as part of the Power Your Drive program (PYD). In addition, this report also references utilization data from SDG&E's applicable SB350 Priority Review Projects (PRPs).

Note: The impact of COVID-19 and shelter-in-place orders had on EV driving and charging behavior is evident throughout the 2020 calendar year. This resulted in some inconsistencies in load patterns when comparing 2019 with 2020 data.

Residential PEV Rates
SDG&E Single-Metered PEV Residential Rates

SDG&E has two residential PEV rates open to new single-metered customers (EV-TOU-2 and EV-TOU-5). In addition, SDG&E has a grandfathered EV rate (EV-TOU-2 (GF)) for NEM customers before June 2017 with legacy time of use periods and is only available to NEM customers for five years.

EV TOU-2:
The EV-TOU-2 rate option is designed for Residential customers that have both their household load and PEV load on the same meter. Service under this optional rate is specifically limited to residential customers who require service for charging a currently registered motor vehicle which is: (1) a battery electric vehicle (BEV) or plug-in hybrid vehicle (PHEV) recharged via a recharging outlet at the customer's premise; or (2) a natural gas vehicle (NGV) refueled via a home refueling appliance (HRA) at the customer's premise.

EV-TOU-2 (GF):
The EV-TOU-2 (GF) rate, which is the grandfathered version of the EV-TOU-2 rate, has the same design criteria as the EV-TOU-2 rate, but with different TOU periods and pricing. This rate is for NEM customers who opted into a TOU tariff prior to July 31, 2017. After the customer's fifth anniversary of the installation of their solar PV system, the customer is not eligible for this rate any longer and must switch to another applicable rate.

EV-TOU-5:
The EV-TOU-5 rate also has the same design criteria as the EV-TOU-2 rate. It has the same TOU periods as the EV-TOU-2 rate, but with different pricing. The main difference is that customers under this rate pay a $16 monthly fixed charge, and subsequently have a much lower super off-peak energy price.

The single-metered rates are designed for residential customers who have their typical load and electric vehicle charging on the same meter. All EV rate plans use an un-tiered TOU rate structure. They offer on-peak, off-peak and super off-peak energy prices according to the time periods and pricing shown in Table SDG&E-1a. Regardless of season, or day of the week, both rates seek to encourage usage in off-peak and super off-peak hours.

SDG&E Separate-Meter PEV Rate (EV-TOU):

The EV-TOU rate option is designed for residential customers that have their PEV load on a dedicated meter and electric service. This is an optional rate for residential customers who require service for charging of a currently registered motor vehicle which is one of the following: (1) a BEV or plugin hybrid electric vehicle (PHEV) recharged via a recharging outlet at the customer’s premise; or (2) an NGV refueled via an HRA at the customer’s premise. The point of service must contain facilities to separately meter PEV or Compressed Natural Gas (CNG) charging.

Table SDG&E-1a: Tariff Type and Rate ($/kWh) in 2019 and 2020

EV-TOU
EV-TOU-2 **2019**

Hour	Winter Weekday	Winter Weekend / Holiday	Summer Weekday	Summer Weekend / Holiday
12mn - 1am	0.24595	0.24595	0.24513	0.24513
1am - 2am	0.24595	0.24595	0.24513	0.24513
2am - 3am	0.24595	0.24595	0.24513	0.24513
3am - 4am	0.24595	0.24595	0.24513	0.24513
4am - 5am	0.24595	0.24595	0.24513	0.24513
5am - 6am	0.24595	0.24595	0.24513	0.24513
6am - 7am	0.25547	0.24595	0.30003	0.24513
7am - 8am	0.25547	0.24595	0.30003	0.24513
8am - 9am	0.25547	0.24595	0.30003	0.24513
9am - 10am	0.25547	0.24595	0.30003	0.24513
10am - 11am	0.25547	0.24595	0.30003	0.24513
11am - 12nn	0.25547	0.24595	0.30003	0.24513
12nn - 1pm	0.25547	0.24595	0.30003	0.24513
1pm - 2pm	0.25547	0.24595	0.30003	0.24513
2pm - 3pm	0.25547	0.25547	0.30003	0.30003
3pm - 4pm	0.25547	0.25547	0.30003	0.30003
4pm - 5pm	0.26403	0.26403	0.53791	0.53791
5pm - 6pm	0.26403	0.26403	0.53791	0.53791
6pm - 7pm	0.26403	0.26403	0.53791	0.53791
7pm - 8pm	0.26403	0.26403	0.53791	0.53791
8pm - 9pm	0.26403	0.26403	0.53791	0.53791
9pm - 10pm	0.25547	0.25547	0.30003	0.30003
10pm - 11pm	0.25547	0.25547	0.30003	0.30003
11pm - 12mn	0.25547	0.25547	0.30003	0.30003

Legend	Winter	Summer
On-Peak		
Off-Peak		
Super Off-Peak		

EV-TOU-5 **2019** **$16/month**

Hour	Winter Weekday	Winter Weekend / Holiday	Summer Weekday	Summer Weekend / Holiday
12mn - 1am	0.09378	0.09378	0.09296	0.09296
1am - 2am	0.09378	0.09378	0.09296	0.09296
2am - 3am	0.09378	0.09378	0.09296	0.09296
3am - 4am	0.09378	0.09378	0.09296	0.09296
4am - 5am	0.09378	0.09378	0.09296	0.09296
5am - 6am	0.09378	0.09378	0.09296	0.09296
6am - 7am	0.24744	0.09378	0.29200	0.09296
7am - 8am	0.24744	0.09378	0.29200	0.09296
8am - 9am	0.24744	0.09378	0.29200	0.09296
9am - 10am	0.24744	0.09378	0.29200	0.09296
10am - 11am	0.24744	0.09378	0.29200	0.09296
11am - 12nn	0.24744	0.09378	0.29200	0.09296
12nn - 1pm	0.24744	0.09378	0.29200	0.09296
1pm - 2pm	0.24744	0.09378	0.29200	0.09296
2pm - 3pm	0.24744	0.24744	0.29200	0.29200
3pm - 4pm	0.24744	0.24744	0.29200	0.29200
4pm - 5pm	0.25600	0.25600	0.52988	0.52988
5pm - 6pm	0.25600	0.25600	0.52988	0.52988
6pm - 7pm	0.25600	0.25600	0.52988	0.52988
7pm - 8pm	0.25600	0.25600	0.52988	0.52988
8pm - 9pm	0.25600	0.25600	0.52988	0.52988
9pm - 10pm	0.24744	0.24744	0.29200	0.29200
10pm - 11pm	0.24744	0.24744	0.29200	0.29200
11pm - 12mn	0.24744	0.24744	0.29200	0.29200

Legend	Winter	Summer
On-Peak		
Off-Peak		
Super Off-Peak		

EV-TOU-2 (GF) **2019**

Hour	Winter Weekday	Winter Weekend / Holiday	Summer Weekday	Summer Weekend / Holiday
12mn - 1am	0.25566	0.25566	0.25655	0.25655
1am - 2am	0.25566	0.25566	0.25655	0.25655
2am - 3am	0.25566	0.25566	0.25655	0.25655
3am - 4am	0.25566	0.25566	0.25655	0.25655
4am - 5am	0.25566	0.25566	0.25655	0.25655
5am - 6am	0.25566	0.25566	0.25655	0.25655
6am - 7am	0.26653	0.25566	0.41184	0.25655
7am - 8am	0.26653	0.25566	0.41184	0.25655
8am - 9am	0.26653	0.25566	0.41184	0.25655
9am - 10am	0.26653	0.25566	0.41184	0.25655
10am - 11am	0.26653	0.25566	0.41184	0.25655
11am - 12nn	0.26653	0.25566	0.41184	0.25655
12nn - 1pm	0.26653	0.25566	0.41184	0.25655
1pm - 2pm	0.26653	0.25566	0.41184	0.25655
2pm - 3pm	0.26653	0.26653	0.41184	0.41184
3pm - 4pm	0.26653	0.26653	0.41184	0.41184
4pm - 5pm	0.26725	0.26725	0.44076	0.44076
5pm - 6pm	0.26725	0.26725	0.44076	0.44076
6pm - 7pm	0.26725	0.26725	0.44076	0.44076
7pm - 8pm	0.26725	0.26725	0.44076	0.44076
8pm - 9pm	0.26725	0.26725	0.44076	0.44076
9pm - 10pm	0.26653	0.26653	0.41184	0.41184
10pm - 11pm	0.26653	0.26653	0.41184	0.41184
11pm - 12mn	0.26653	0.26653	0.41184	0.41184

Legend	Winter	Summer
On-Peak		
Off-Peak		
Super Off-Peak		

EV-TOU
EV-TOU-2 **2020**

Hour	Winter Weekday	Winter Weekend / Holiday	Summer Weekday	Summer Weekend / Holiday
12mn - 1am	0.19386	0.19386	0.19313	0.19313
1am - 2am	0.19386	0.19386	0.19313	0.19313
2am - 3am	0.19386	0.19386	0.19313	0.19313
3am - 4am	0.19386	0.19386	0.19313	0.19313
4am - 5am	0.19386	0.19386	0.19313	0.19313
5am - 6am	0.19386	0.19386	0.19313	0.19313
6am - 7am	0.29766	0.19386	0.33777	0.19313
7am - 8am	0.29766	0.19386	0.33777	0.19313
8am - 9am	0.29766	0.19386	0.33777	0.19313
9am - 10am	0.29766	0.19386	0.33777	0.19313
10am - 11am	0.29766	0.19386	0.33777	0.19313
11am - 12nn	0.29766	0.19386	0.33777	0.19313
12nn - 1pm	0.29766	0.19386	0.33777	0.19313
1pm - 2pm	0.29766	0.19386	0.33777	0.19313
2pm - 3pm	0.29766	0.29766	0.33777	0.33777
3pm - 4pm	0.29766	0.29766	0.33777	0.33777
4pm - 5pm	0.30536	0.30536	0.55170	0.55170
5pm - 6pm	0.30536	0.30536	0.55170	0.55170
6pm - 7pm	0.30536	0.30536	0.55170	0.55170
7pm - 8pm	0.30536	0.30536	0.55170	0.55170
8pm - 9pm	0.30536	0.30536	0.55170	0.55170
9pm - 10pm	0.29766	0.29766	0.33777	0.33777
10pm - 11pm	0.29766	0.29766	0.33777	0.33777
11pm - 12mn	0.29766	0.29766	0.33777	0.33777

Legend	Winter	Summer
On-Peak		
Off-Peak		
Super Off-Peak		

EV-TOU-5	2020	$16/month		
Hour	**Winter Weekday**	**Winter Weekend / Holiday**	**Summer Weekday**	**Summer Weekend / Holiday**
12mn - 1am	0.08619	0.08619	0.08546	0.08546
1am - 2am	0.08619	0.08619	0.08546	0.08546
2am - 3am	0.08619	0.08619	0.08546	0.08546
3am - 4am	0.08619	0.08619	0.08546	0.08546
4am - 5am	0.08619	0.08619	0.08546	0.08546
5am - 6am	0.08619	0.08619	0.08546	0.08546
6am - 7am	0.24893	0.08619	0.28904	0.08546
7am - 8am	0.24893	0.08619	0.28904	0.08546
8am - 9am	0.24893	0.08619	0.28904	0.08546
9am - 10am	0.24893	0.08619	0.28904	0.08546
10am - 11am	0.24893	0.08619	0.28904	0.08546
11am - 12nn	0.24893	0.08619	0.28904	0.08546
12nn - 1pm	0.24893	0.08619	0.28904	0.08546
1pm - 2pm	0.24893	0.08619	0.28904	0.08546
2pm - 3pm	0.24893	0.24893	0.28904	0.28904
3pm - 4pm	0.24893	0.24893	0.28904	0.28904
4pm - 5pm	0.25663	0.25663	0.50297	0.50297
5pm - 6pm	0.25663	0.25663	0.50297	0.50297
6pm - 7pm	0.25663	0.25663	0.50297	0.50297
7pm - 8pm	0.25663	0.25663	0.50297	0.50297
8pm - 9pm	0.25663	0.25663	0.50297	0.50297
9pm - 10pm	0.24893	0.24893	0.28904	0.28904
10pm - 11pm	0.24893	0.24893	0.28904	0.28904
11pm - 12mn	0.24893	0.24893	0.28904	0.28904

Legend	**Winter**	**Summer**
On-Peak		
Off-Peak		
Super Off-Peak		

EV-TOU-2 (GF) **2020**

Hour	Winter Weekday	Winter Weekend / Holiday	Summer Weekday	Summer Weekend / Holiday
12mn - 1am	0.20258	0.20258	0.20339	0.20339
1am - 2am	0.20258	0.20258	0.20339	0.20339
2am - 3am	0.20258	0.20258	0.20339	0.20339
3am - 4am	0.20258	0.20258	0.20339	0.20339
4am - 5am	0.20258	0.20258	0.20339	0.20339
5am - 6am	0.20258	0.20258	0.20339	0.20339
6am - 7am	0.29231	0.20258	0.42309	0.20339
7am - 8am	0.29231	0.20258	0.42309	0.20339
8am - 9am	0.29231	0.20258	0.42309	0.20339
9am - 10am	0.29231	0.20258	0.42309	0.20339
10am - 11am	0.29231	0.20258	0.42309	0.20339
11am - 12nn	0.29231	0.20258	0.42309	0.20339
12nn - 1pm	0.29231	0.20258	0.42309	0.20339
1pm - 2pm	0.29231	0.20258	0.42309	0.20339
2pm - 3pm	0.29231	0.29231	0.42309	0.42309
3pm - 4pm	0.29231	0.29231	0.42309	0.42309
4pm - 5pm	0.29294	0.29294	0.44887	0.44887
5pm - 6pm	0.29294	0.29294	0.44887	0.44887
6pm - 7pm	0.29294	0.29294	0.44887	0.44887
7pm - 8pm	0.29294	0.29294	0.44887	0.44887
8pm - 9pm	0.29294	0.29294	0.44887	0.44887
9pm - 10pm	0.29231	0.29231	0.42309	0.42309
10pm - 11pm	0.29231	0.29231	0.42309	0.42309
11pm - 12mn	0.29231	0.29231	0.42309	0.42309

Legend	Winter	Summer
On-Peak		
Off-Peak		
Super Off-Peak		

SDG&E Table 1b shows the price ratios between the different TOU periods for each EV rate for 2019 and 2020. All four rates have the largest difference between on-peak and super off-peak prices during the summer season.

SDG&E Table 1b: Price Ratios for EV Rates (2019 and 2020)

Tariff	Winter 2019		Summer 2019	
	Off-Peak to Super Off-Peak Ratio	On-Peak to Super Off-Peak Ratio	Off-Peak to Super Off-Peak Ratio	On-Peak to Super Off-Peak Ratio
EV-TOU	1.04	1.07	1.22	2.19
EV-TOU-2	1.04	1.07	1.22	2.19
EV-TOU-2 (GF)	1.04	1.05	1.61	1.72
EV-TOU-5	2.64	2.73	3.14	5.70

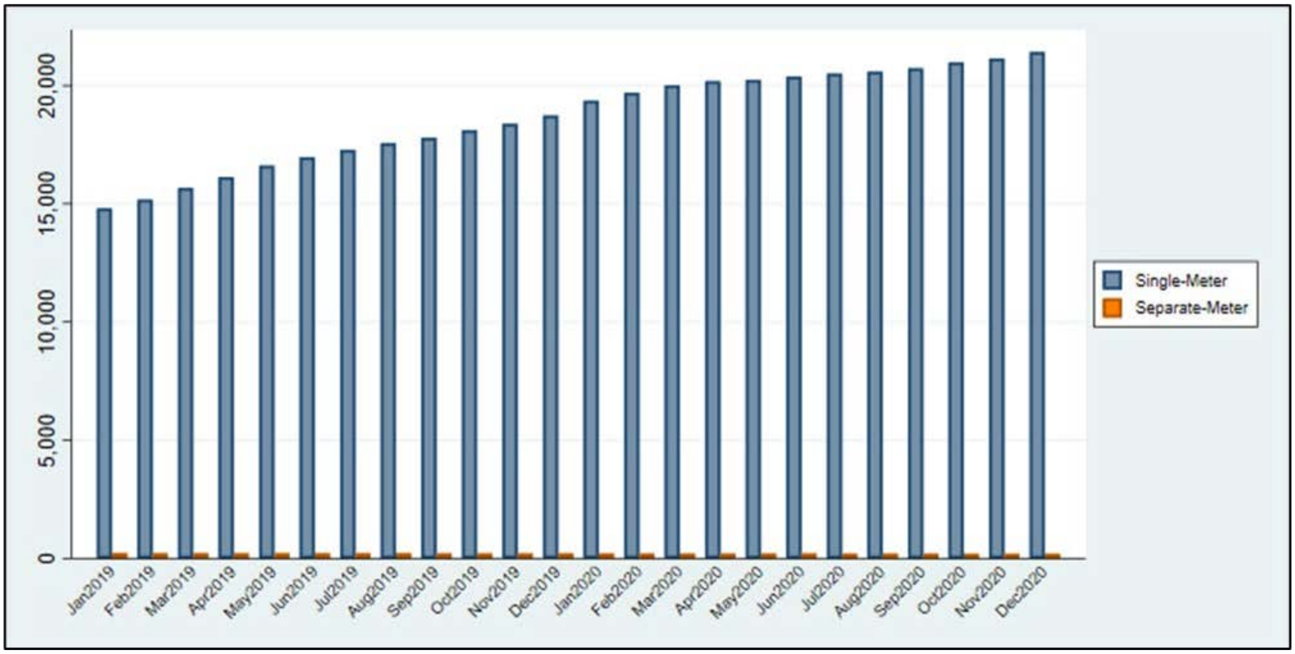
Tariff	Winter 2020		Summer 2020	
	Off-Peak to Super Off-Peak Ratio	On-Peak to Super Off-Peak Ratio	Off-Peak to Super Off-Peak Ratio	On-Peak to Super Off-Peak Ratio
EV-TOU	1.54	1.58	1.75	2.86
EV-TOU-2	1.54	1.58	1.75	2.86
EV-TOU-2 (GF)	1.44	1.45	2.08	2.21
EV-TOU-5	2.89	2.98	3.38	5.89

Single-Metered Rate Growth

Participation in the single-metered PEV rates showed a steady increase during 2019 and 2020 (26.6% and 10.7%, respectively). Participation in the separately-metered PEV rate decreased slightly during 2019 through 2020 (-5% and -4.4%, respectively) and is a much smaller set of customers than the single-metered PEV rates. It is important to note that not all PEV customers have adopted PEV rates. Of the customers on PEV rates, the majority are on one of the single-metered rates.

Single-Metered Customers: SDG&E Chart-1 below displays the total customers on the single-metered PEV rates. During the study period, there was a steady increase in single-metered rate enrollment overall.

SDG&E Chart 1: Single and Separate Metering Accounts by Meter Configuration



Referencing SDG&E Table-4 and SDG&E Chart-1, the number of SDG&E's customers taking service under separately metered EV rates has slowly decreased over the past two years. This is most likely due to a small number of customers switching to a single-metered configuration to better accommodate NEM or to get a better whole-house EV rate choice (EV-TOU-5). Most of the customers who have left the single meter configuration participated in SDG&E's Plugin Electric Vehicle TOU Pricing and Technology Study pilot program from 2011-2013.[34]

The average monthly usage for PEV customers follows similar seasonal patterns when comparing NEM and non-NEM single-meter PEV customers. Assuming the PEV charging load by itself is approximately 220-260 kWh monthly, the household load for single-meter customers is a little less than double the average residential customer load of 445 kWh per month.

NEM Single-Metered Customers: Net Energy Metering (NEM) customers on the PEV rates are an important group to consider. Of all the SDG&E customers who were on the single-metered PEV rates in December 2020, 44% were also NEM customers.

The fact that NEM customers with PEVs predominately use the single-metered rate presents a load research challenge when trying to ascertain how much energy is used by the house and the EV(s) due to a lack of metering data in these situations (EV charging energy and residential solar energy is usually not separately metered by the utility for these customers). In addition, the now-popular installation of onsite distributed generation (DG) in the form of battery

[34] See report at https://www.sdge.com/sites/default/files/SDGE%20EV%20%20Pricing%20%26%20Tech%20Study.pdf

storage tends to exacerbate the data / load research issue because of that lack of metering as well. Without additional metering of the DG and/or solar PV systems, it is not possible to isolate the effect PEV ownership has on usage patterns for this group using the utility metering data alone.

SDG&E Table 2a: Total Single-Metered NEM Program Enrollment (2019 – 2020)

Month	Total Customers on Single-Metering	Total Customers on NEM	NEM as a % of Single-Metering
Jan 2019	14,803	5,357	36.2%
Feb 2019	15,175	5,558	36.6%
Mar 2019	15,673	5,801	37.0%
Apr 2019	16,132	5,980	37.1%
May 2019	16,612	6,188	37.3%
Jun 2019	16,971	6,369	37.5%
Jul 2019	17,282	6,542	37.9%
Aug 2019	17,562	6,713	38.2%
Sep 2019	17,791	6,853	38.5%
Oct 2019	18,115	7,058	39.0%
Nov 2019	18,380	7,252	39.5%
Dec 2019	18,735	7,472	39.9%
Jan 2020	19,355	7,847	40.5%
Feb 2020	19,696	8,084	41.0%
Mar 2020	20,011	8,278	41.4%
Apr 2020	20,184	8,376	41.5%
May 2020	20,242	8,448	41.7%
Jun 2020	20,380	8,532	41.9%
Jul 2020	20,501	8,623	42.1%
Aug 2020	20,584	8,707	42.3%
Sep 2020	20,727	8,853	42.7%
Oct 2020	20,975	9,026	43.0%
Nov 2020	21,145	9,174	43.4%
Dec 2020	21,418	9,389	43.8%

SDG&E Table 2b: Single-Metered NEM Program Enrollment for EV-TOU-2 (2019 – 2020)

Month	Total Customers on EVTOU2	Total Customers on NEM	NEM as a % of EVTOU2
Jan 2019	9,102	1,956	21.5%
Feb 2019	9,032	2,033	22.5%
Mar 2019	8,956	2,101	23.5%
Apr 2019	8,844	2,152	24.3%
May 2019	8,760	2,234	25.5%
Jun 2019	8,633	2,328	27.0%
Jul 2019	8,508	2,385	28.0%
Aug 2019	8,329	2,421	29.1%
Sep 2019	8,184	2,453	30.0%
Oct 2019	8,141	2,526	31.0%
Nov 2019	8,085	2,585	32.0%
Dec 2019	8,069	2,646	32.8%
Jan 2020	8,166	2,811	34.4%
Feb 2020	8,151	2,883	35.4%
Mar 2020	8,172	2,964	36.3%
Apr 2020	8,127	2,999	37.0%
May 2020	8,109	3,050	37.6%
Jun 2020	8,107	3,114	38.4%
Jul 2020	8,103	3,177	39.2%
Aug 2020	8,040	3,211	40.0%
Sep 2020	8,009	3,290	41.1%
Oct 2020	8,026	3,364	41.9%
Nov 2020	8,041	3,473	43.2%
Dec 2020	8,071	3,601	44.6%

SDG&E Table 2c: Single-Metered NEM Program Enrollment for GEV-TOU2 (2019 – 2020)

Month	Total Customers on GEVTOU2	Total Customers on NEM	NEM as a % of GEVTOU2
Jan 2019	2,595	2,595	100.0%
Feb 2019	2,552	2,552	100.0%
Mar 2019	2,473	2,473	100.0%
Apr 2019	2,408	2,408	100.0%
May 2019	2,341	2,341	100.0%
Jun 2019	2,260	2,260	100.0%
Jul 2019	2,169	2,169	100.0%
Aug 2019	2,103	2,103	100.0%
Sep 2019	2,048	2,048	100.0%
Oct 2019	1,991	1,991	100.0%
Nov 2019	1,935	1,935	100.0%
Dec 2019	1,891	1,891	100.0%
Jan 2020	1,843	1,843	100.0%
Feb 2020	1,766	1,766	100.0%
Mar 2020	1,722	1,722	100.0%
Apr 2020	1,662	1,662	100.0%
May 2020	1,620	1,620	100.0%
Jun 2020	1,569	1,569	100.0%
Jul 2020	1,520	1,520	100.0%
Aug 2020	1,465	1,465	100.0%
Sep 2020	1,419	1,419	100.0%
Oct 2020	1,353	1,353	100.0%
Nov 2020	1,306	1,306	100.0%
Dec 2020	1,215	1,215	100.0%

SDG&E Table 2d: Single-Metered NEM Program Enrollment for EV-TOU5 (2019 – 2020)

Month	Total Customers on EVTOU5	Total Customers on NEM	NEM as a % of EVTOU5
Jan 2019	3,230	861	26.7%
Feb 2019	3,796	1,064	28.0%
Mar 2019	4,484	1,332	29.7%
Apr 2019	5,094	1,502	29.5%
May 2019	5,772	1,722	29.8%
Jun 2019	6,289	1,891	30.1%
Jul 2019	6,799	2,077	30.6%
Aug 2019	7,299	2,271	31.1%
Sep 2019	7,680	2,411	31.4%
Oct 2019	8,097	2,610	32.2%
Nov 2019	8,462	2,800	33.1%
Dec 2019	8,866	2,984	33.7%
Jan 2020	9,488	3,298	34.8%
Feb 2020	9,883	3,512	35.6%
Mar 2020	10,232	3,672	35.9%
Apr 2020	10,480	3,765	35.9%
May 2020	10,622	3,848	36.2%
Jun 2020	10,802	3,913	36.2%
Jul 2020	11,010	4,015	36.5%
Aug 2020	11,214	4,105	36.6%
Sep 2020	11,428	4,232	37.0%
Oct 2020	11,723	4,392	37.5%
Nov 2020	11,991	4,527	37.8%
Dec 2020	12,341	4,714	38.2%

SDG&E analyzed usage patterns of customers on EV rates, whose characteristics (including consumption patterns) are often different from the general population (for example, NEM customers with PV systems). Currently, solar PV owners are overrepresented in the PEV-rate class as compared to non-PEV customers. NEM penetration for the residential population in SDG&E's service territory is about 15%, while NEM customers currently represent approximately 44% of the single-meter PEV-rate class (as seen in SDG&E Table 2a – December 2020). Between January 2019 and December 2020, the population on SDG&E's EV rates increased over 40%, while the NEM subset saw similar increases.

Separately-Metered Rate Growth

All Separately-metered Customers: The separately-metered PEV rate remains a less popular option for PEV rate customers than the single-metered PEV rate, due to the expense of installing a new electric service and a separate meter.

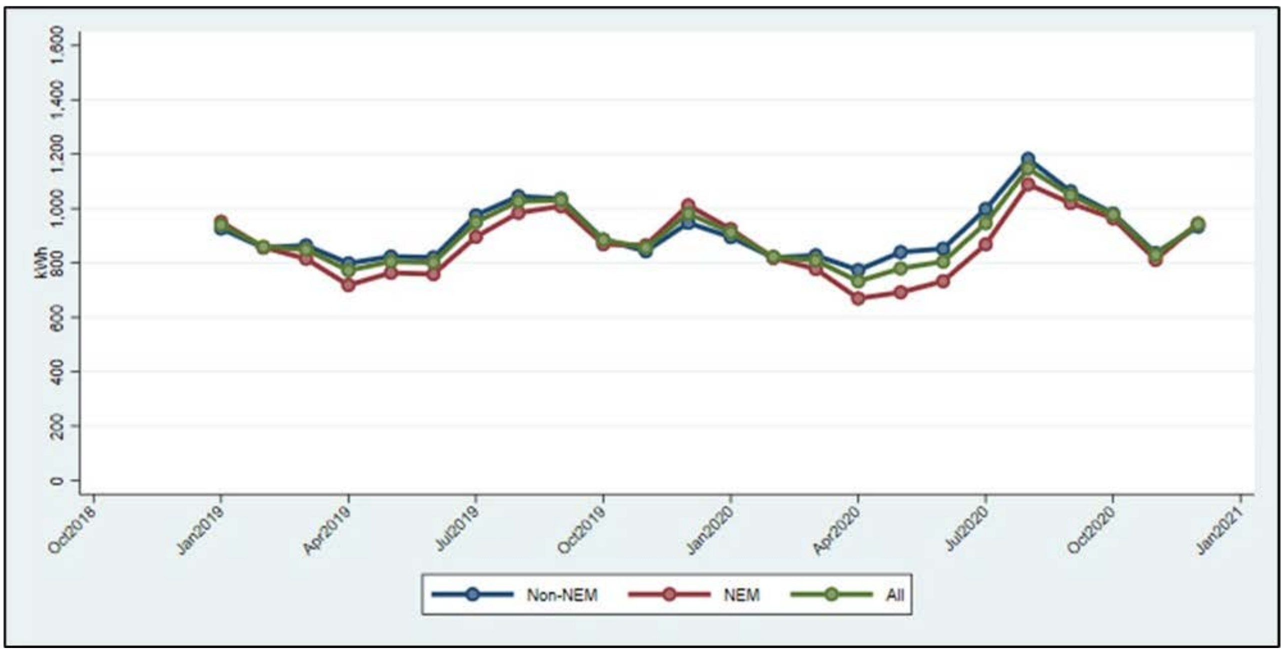
Table SDG&E-4: Separately-Metered Accounts Totals (2019 and 2020)

Month	Total Customers on Separate-Metering	Total Customers on NEM	NEM as a % of Separate-Metering
Jan 2019	219	86	39.3%
Feb 2019	214	83	38.8%
Mar 2019	214	83	38.8%
Apr 2019	212	82	38.7%
May 2019	213	80	37.6%
Jun 2019	212	80	37.7%
Jul 2019	212	82	38.7%
Aug 2019	215	86	40.0%
Sep 2019	208	85	40.9%
Oct 2019	207	82	39.6%
Nov 2019	206	83	40.3%
Dec 2019	208	83	39.9%
Jan 2020	205	82	40.0%
Feb 2020	202	82	40.6%
Mar 2020	202	82	40.6%
Apr 2020	202	83	41.1%
May 2020	203	82	40.4%
Jun 2020	205	82	40.0%
Jul 2020	200	80	40.0%
Aug 2020	199	79	39.7%
Sep 2020	199	79	39.7%
Oct 2020	194	77	39.7%
Nov 2020	195	78	40.0%
Dec 2020	196	81	41.3%

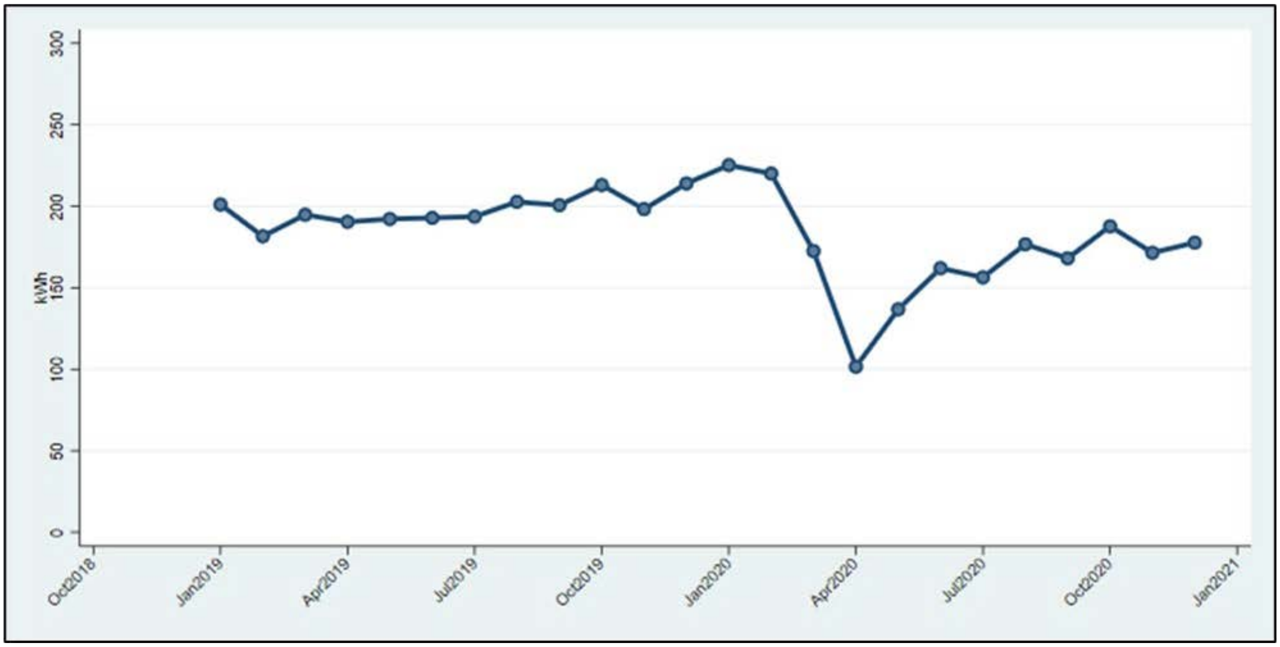
Average Monthly Usage for PEV Rate Customers

SDG&E Chart-3 displays the average monthly usage for single-metered customers with and without NEM during 2019 and 2020, which is the average monthly usage including behind-the-meter generation. SDG&E Chart-3 displays the average monthly usage for each single-metered category without NEM. Note that average consumption in Chart 3 shows a small drop in April 2020 (assumed due to Covid-19), while the drop in Chart 5 during April and beyond is much more noticeable due to car charging being isolated (less driving during the stay at home period in 2020).

SDG&E Chart 3: Average Monthly Usage for Single-Meter Customers With and Without NEM (2019 – 2020)



SDG&E Chart 5: Average Monthly Usage for Separate-Meter Customers (2019 – 2020)



Time of Use Analysis of Single- and Separate-Meter Customers

One of the questions addressed in this report is whether being on a TOU rate with higher on-peak pricing is an effective incentive to move EV charging or other household consumption to off-peak or super off-peak times. The load shapes provided in SDG&E Charts 7 and 8 suggest that customers respond to differences in prices and charge their vehicles when electricity is the cheapest. SDG&E Tables 6a-6f below provides the percentage share of monthly kWh for single and separate-meter rates. EV-TOU-2 (GF) customers consume slightly over 50% of their energy during the off-peak TOU period and split the rest between on-peak and super off-peak at approximately 10% and 36% respectively. Total EV-TOU-2 customers consume approximately 36% of their energy during the off-peak TOU period and split the rest between on-peak and super off-peak at approximately 24% and 40% respectively. NEM EV-TOU-2 customers respond fairly well to the signal created by the TOU price differential and consume on average about 45% of their energy during the super off-peak TOU period. Separate-Meter customers respond very well to the signal created by the TOU price differential and consume on average almost 80% of their energy during the super off-peak TOU period.

SDG&E Table 6a: Percentage of On-Peak Usage by Single-Meter Configuration

Year	Season	EVTOU2 Non-NEM	EVTOU2 NEM	EVTOU2 Total	EVTOU2 (GF) Total	EVTOU5 Non-NEM	EVTOU5 NEM	EVTOU5 Total
2019	S	23.1%	24.4%	23.5%	9.4%	18.5%	18.3%	18.5%
2019	W	22.6%	24.8%	23.1%	10.8%	18.2%	19.0%	18.5%
2020	S	25.1%	28.0%	26.1%	12.9%	21.4%	22.6%	21.9%
2020	W	24.0%	27.7%	25.3%	11.4%	20.1%	21.8%	20.7%

SDG&E Table 6b: Percentage of On-Peak Usage by Separate-Meter Configuration

Year	Season	EVTOU Non-NEM	EVTOU NEM	EVTOU Total
2019	S	14.1%	6.8%	11.7%
2019	W	13.9%	7.7%	11.8%
2020	S	18.6%	6.8%	16.0%
2020	W	16.8%	8.0%	14.5%

SDG&E Table 6c: Percentage of Off-Peak Usage by Single-Meter Configuration

Year	Season	EVTOU2 Non-NEM	EVTOU2 NEM	EVTOU2 Total	EVTOU2 (GF) Total	EVTOU5 Non-NEM	EVTOU5 NEM	EVTOU5 Total
2019	S	41.1%	30.7%	38.3%	55.0%	34.4%	25.3%	31.4%
2019	W	36.5%	29.4%	34.7%	53.6%	30.7%	23.8%	28.4%
2020	S	43.1%	32.5%	39.3%	56.8%	38.2%	28.9%	34.7%
2020	W	37.7%	29.4%	34.8%	56.1%	32.6%	25.1%	29.8%

SDG&E Table 6d: Percentage of Off-Peak Usage by Separate-Meter Configuration

Year	Season	EVTOU Non-NEM	EVTOU NEM	EVTOU Total
2019	S	19.9%	14.0%	18.0%
2019	W	18.3%	14.3%	16.9%
2020	S	26.6%	15.2%	24.1%
2020	W	24.1%	14.4%	21.5%

SDG&E Table 6e: Percentage of Super Off-Peak Usage by Single-Meter Configuration

Year	Season	EVTOU2 Non-NEM	EVTOU2 NEM	EVTOU2 Total	EVTOU2 (GF) Total	EVTOU5 Non-NEM	EVTOU5 NEM	EVTOU5 Total
2019	S	35.8%	44.9%	38.2%	35.5%	47.1%	56.4%	50.2%
2019	W	41.0%	45.8%	42.2%	35.5%	51.1%	57.2%	53.2%
2020	S	31.9%	39.5%	34.6%	30.3%	40.4%	48.5%	43.4%
2020	W	38.3%	42.9%	39.9%	32.5%	47.3%	53.2%	49.5%

SDG&E Table 6f: Percentage of Super Off-Peak Usage by Separate-Meter Configuration

Year	Season	EVTOU Non-NEM	EVTOU NEM	EVTOU Total
2019	S	66.0%	79.3%	70.3%
2019	W	67.8%	78.0%	71.3%
2020	S	54.8%	77.9%	60.0%
2020	W	59.1%	77.6%	64.0%

Average Load Profiles

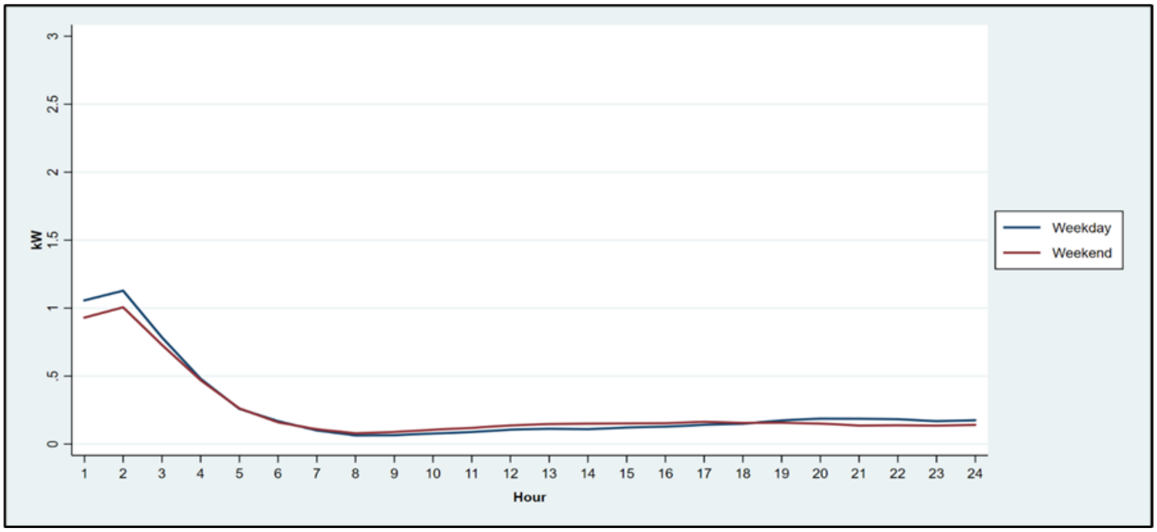
SDG&E Charts 8a through 8d compare the average load profiles for weekdays versus weekends for EV-TOU-2, EV-TOU-2 (GF), EV-TOU-5 and the combination of the three on a net basis. The net load shapes for EV-TOU-2 and EV-TOU-5 remain relatively flat during the day with an increase in evening consumption. This behavior is similar to a typical residential net load profile except that there is a large spike in the early morning (super off-peak) hours. This is the effect of customers taking advantage of the super off-peak pricing to charge their vehicles. Weekends tend to have higher midday consumption because most customers are usually at home rather than going to work. Weekends also have lower charging levels during the early morning hours.

Since many customers change their behavior to take advantage of super off-peak pricing, charging occurs in the early morning on the day after the vehicle was used (assuming they are driven to work Monday – Friday). If the electric vehicle sits idle during the weekend (Saturday and Sunday), significant charging is not conducted on Sunday and Monday.

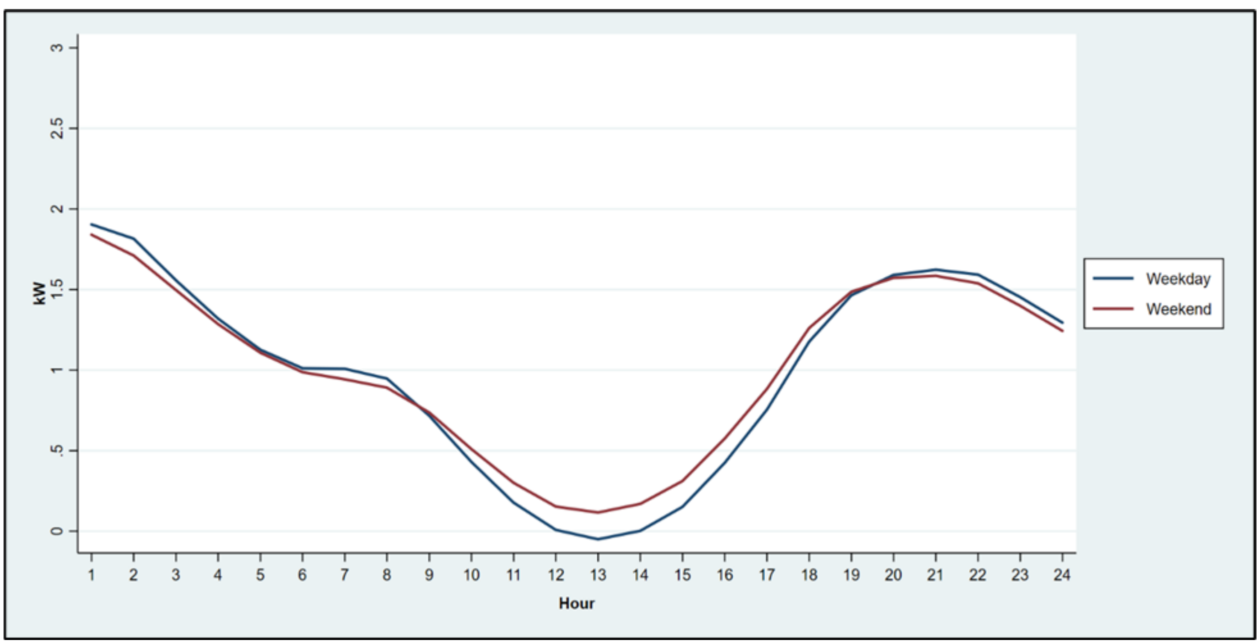
Another observation is that the net load shape for EV-TOU-2 (GF) shows an observable dip in the midday hours due to PV generation from NEM customers (all customers on EV-TOU-2 (GF) are NEM customers).

SDG&E Chart 7 displays similar day of week patterns for separate-meter PEV customers. These accounts peak in the 01:00 – 02:00 hour timeframe and have negligible consumption during the rest of the day. This would indicate that the rate structure and enabling technology are successful in encouraging charging mainly during the super off-peak hours. This chart also shows that EV charging consumption on Sundays and Mondays is lower than the rest of the week, which is consistent with single-meter customers.

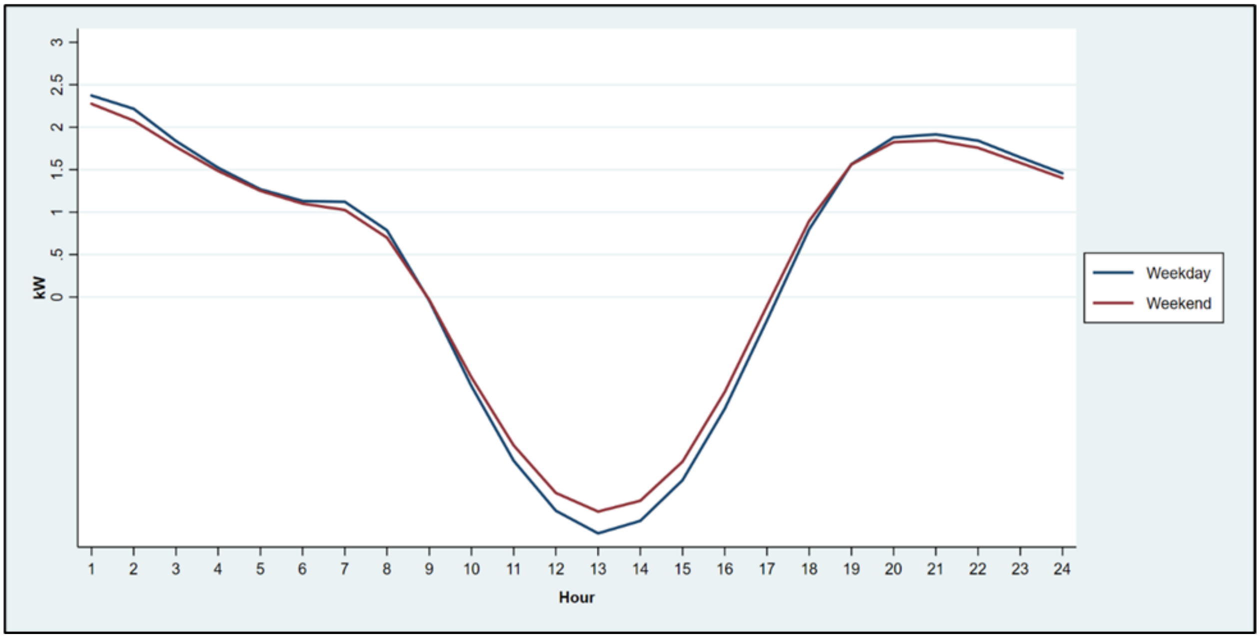
SDG&E Chart 7: Average Net Load Profile for Separate-Meter Customers (EV-TOU) by Weekday/Weekend for 2019-2020



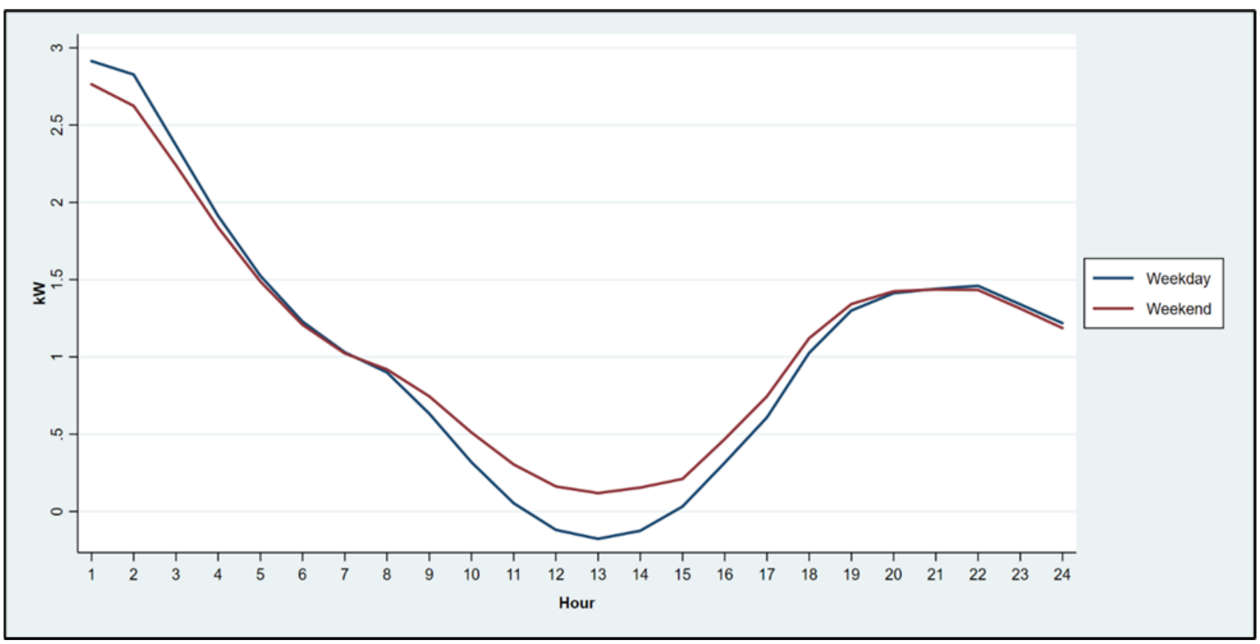
SDG&E Chart 8a: Average Net Load Profile for EV-TOU-2 by Weekday/Weekend for 2019-2020



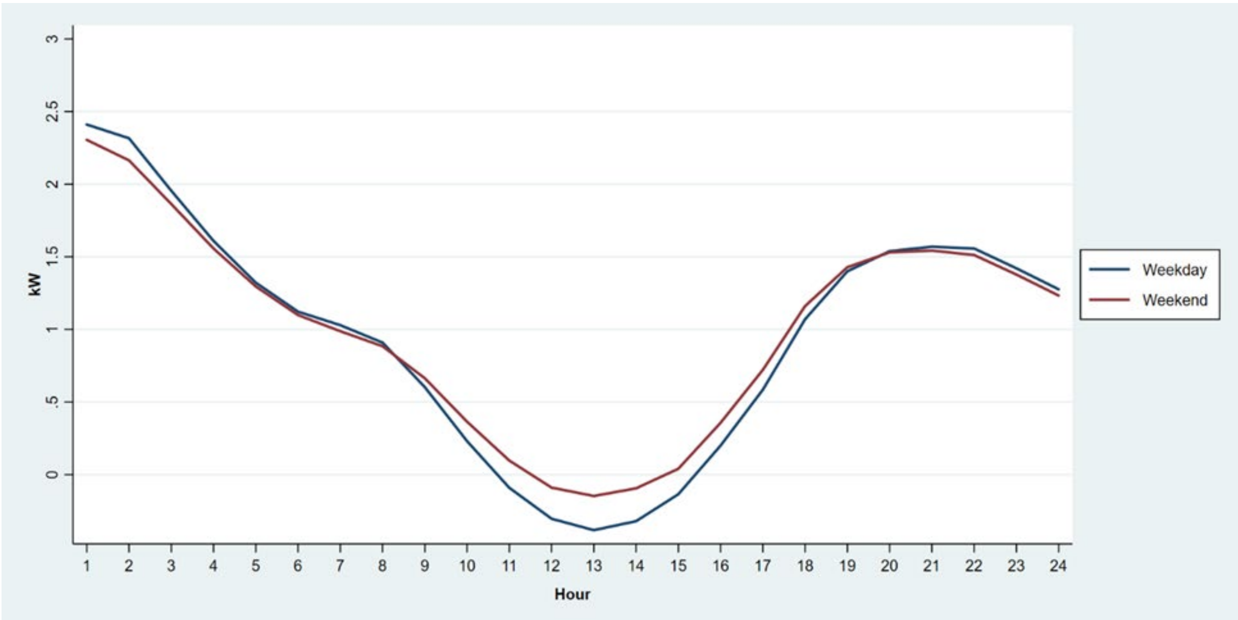
SDG&E Chart 8b: Average Net Load Profile for EV-TOU-2 (GF)
by Weekday/Weekend for 2019-2020



SDG&E Chart 8c: Average Net Load Profile for EV-TOU-5
by Weekday/Weekend for 2019-2020



SDG&E Chart 8d: Average Net Load Profile for All Single-Meter Customers by Weekday/Weekend



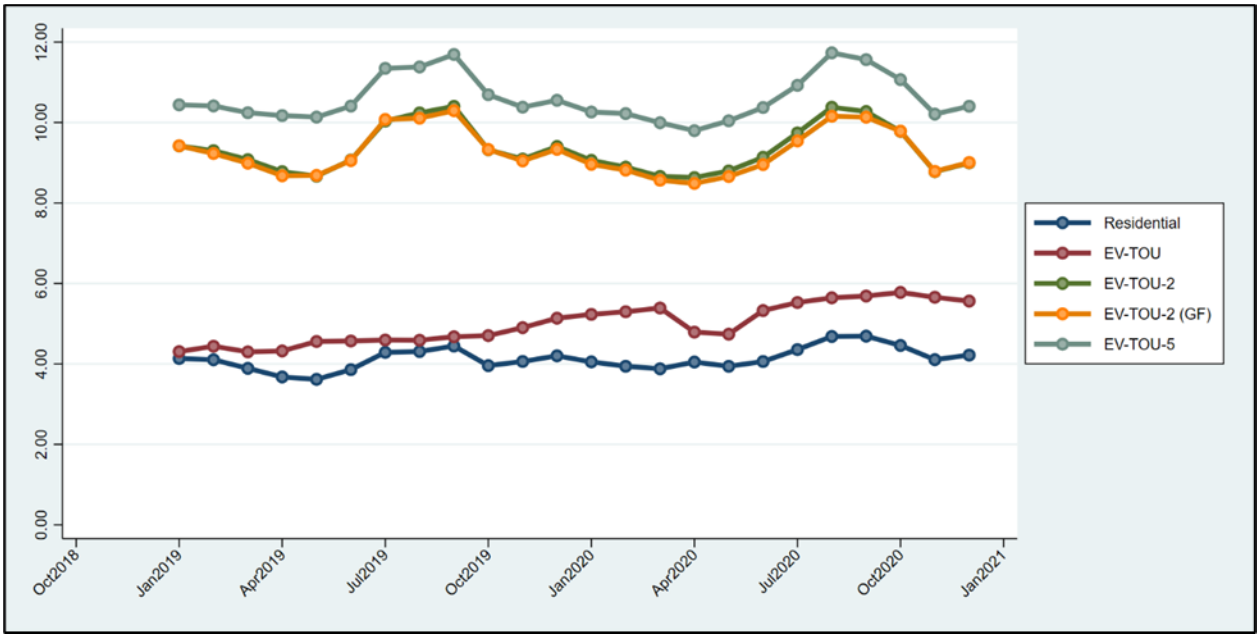
Average Maximum Peak Load

SDG&E Table 9 shows that the average maximum (also referred to as Non-Coincident) peak demand for separate-meter customers is slightly over 4 kW. For reference, this is roughly the maximum power shown in the 7th Joint IOU Electric Vehicle Load Research Report: April 2019 for Leaf EVs / Blink EVSEs. Single-meter customers have a maximum demand more than twice that of the average residential customer, which is driven by the addition of the EV charging load to the base house load.

SDG&E Table 9: Average Maximum Peak Load (kW) by Customer Type and Month

Month	Residential Pop.	EV-TOU	EV-TOU-2	EV-TOU-2 (GF)	EV-TOU-5
Jan 2019	4.13	4.31	9.42	9.42	10.44
Feb 2019	4.10	4.44	9.30	9.23	10.41
Mar 2019	3.89	4.30	9.08	8.99	10.24
Apr 2019	3.68	4.32	8.78	8.68	10.17
May 2019	3.62	4.56	8.67	8.68	10.13
Jun 2019	3.86	4.57	9.07	9.05	10.41
Jul 2019	4.29	4.60	10.04	10.07	11.35
Aug 2019	4.31	4.59	10.24	10.11	11.38
Sep 2019	4.44	4.68	10.40	10.30	11.69
Oct 2019	3.96	4.70	9.32	9.33	10.69
Nov 2019	4.06	4.90	9.09	9.05	10.38
Dec 2019	4.20	5.14	9.40	9.33	10.55
Jan 2020	4.05	5.23	9.06	8.96	10.26
Feb 2020	3.94	5.30	8.89	8.82	10.22
Mar 2020	3.88	5.39	8.66	8.56	10.00
Apr 2020	4.05	4.79	8.63	8.49	9.80
May 2020	3.94	4.74	8.80	8.66	10.04
Jun 2020	4.06	5.33	9.14	8.96	10.37
Jul 2020	4.36	5.53	9.74	9.54	10.92
Aug 2020	4.68	5.64	10.38	10.16	11.73
Sep 2020	4.69	5.69	10.27	10.13	11.56
Oct 2020	4.46	5.78	9.78	9.78	11.07
Nov 2020	4.11	5.66	8.78	8.79	10.21
Dec 2020	4.22	5.56	9.00	9.01	10.40

SDG&E Chart 9: Average Maximum Peak Load (kW) by Customer Type and Month



Time and Average Diversified Peak Load

With the exception of EV-TOU-2 customers in September and October, and EV-TOU-2 (GF) customers in July, both single-meter and separate-meter customers peak around 12:30 AM and 01:30 AM driven by PEV charging behavior as shown in SDG&E Table 10. As a comparison, the residential class peaks in the early evening hours.

SDG&E Table 10: Time and Associated Demand of Diversified Peak Load

Month	Residential		EV-TOU-2		EV-TOU-2 (GF)		EV-TOU-5		EV-TOU	
	Time	kW	Time	kW	Time	kW	Time	kW	Time	kW
Jan 2019	7:00PM	1.03	1:15AM	2.92	12:45AM	2.94	1:15AM	4.46	1:30AM	1.68
Feb 2019	7:15PM	1.01	1:15AM	2.96	12:45AM	3.08	1:15AM	4.41	12:45AM	1.79
Mar 2019	7:30PM	0.93	1:15AM	2.77	12:45AM	2.76	1:15AM	4.13	1:15AM	1.71
Apr 2019	8:00PM	0.79	1:15AM	2.68	12:45AM	2.69	1:15AM	4.24	1:15AM	1.83
May 2019	8:30PM	0.72	12:45AM	2.65	12:45AM	2.65	1:15AM	4.26	1:15AM	1.89
Jun 2019	8:30PM	0.86	1:15AM	2.79	1:15AM	2.81	12:45AM	4.44	1:30AM	1.81
Jul 2019	6:45PM	1.11	12:45AM	3.30	12:15AM	3.26	12:45AM	5.05	1:15AM	1.70
Aug 2019	8:15PM	1.18	12:45AM	3.12	12:45AM	3.14	12:45AM	4.77	1:30AM	1.95

Sep 2019	6:30PM	1.33	12:45AM	3.46	12:45AM	3.49	12:45AM	5.17	1:30AM	1.91
Oct 2019	6:45PM	0.96	12:45AM	2.85	12:45AM	2.95	12:45AM	4.56	1:30AM	2.01
Nov 2019	11:45AM	1.04	12:45AM	4.14	12:15AM	4.29	12:45AM	6.49	12:45AM	1.95
Dec 2019	7:45PM	0.98	1:15AM	2.82	12:45AM	2.93	1:15AM	4.49	1:15AM	1.89
Jan 2020	6:00PM	0.88	1:15AM	2.74	1:15AM	2.73	12:45AM	4.39	1:15AM	2.08
Feb 2020	6:15PM	0.89	1:15AM	2.76	12:45AM	2.89	1:15AM	4.43	1:30AM	1.91
Mar 2020	7:45PM	0.87	12:45AM	2.54	1:15AM	2.60	1:15AM	4.18	1:30AM	1.73
Apr 2020	7:45PM	0.94	8:15PM	2.20	8:15PM	2.24	12:45AM	2.73	12:45AM	0.92
May 2020	7:00PM	1.04	7:45PM	2.32	7:15PM	2.30	12:45AM	2.96	12:45AM	1.03
Jun 2020	7:00PM	1.11	8:15PM	2.61	8:00PM	2.63	12:45AM	3.42	1:15AM	1.18
Jul 2020	6:15PM	1.31	9:15PM	2.86	8:30PM	2.83	12:45AM	3.60	1:30AM	1.17
Aug 2020	6:00PM	1.54	6:45PM	3.29	7:15PM	3.48	12:45AM	4.19	1:30AM	1.23
Sep 2020	4:00PM	1.82	6:15PM	3.79	7:00PM	3.89	12:45AM	4.03	1:30AM	1.27
Oct 2020	6:00PM	1.48	6:15PM	3.16	7:15PM	3.34	12:45AM	4.06	1:30AM	1.48
Nov 2020	6:45PM	0.89	12:15AM	3.66	12:15AM	3.58	12:30AM	5.46	12:30AM	1.88
Dec 2020	6:30PM	1.00	6:00PM	2.20	1:15AM	2.17	12:45AM	3.46	12:45AM	1.25

SDG&E Transportation Electrification Program Load Data Section

2019 Results

For SDG&E Charts 11a and 11b below, the total energy consumption per site per month was aggregated into a sum of total consumption per month per segment type. Then the average of that consumption was calculated by dividing the Total Consumption by the Total Station Count per month. Finally, the total station count per site per month data was aggregated to arrive at the total station count per month per segment type numbers.

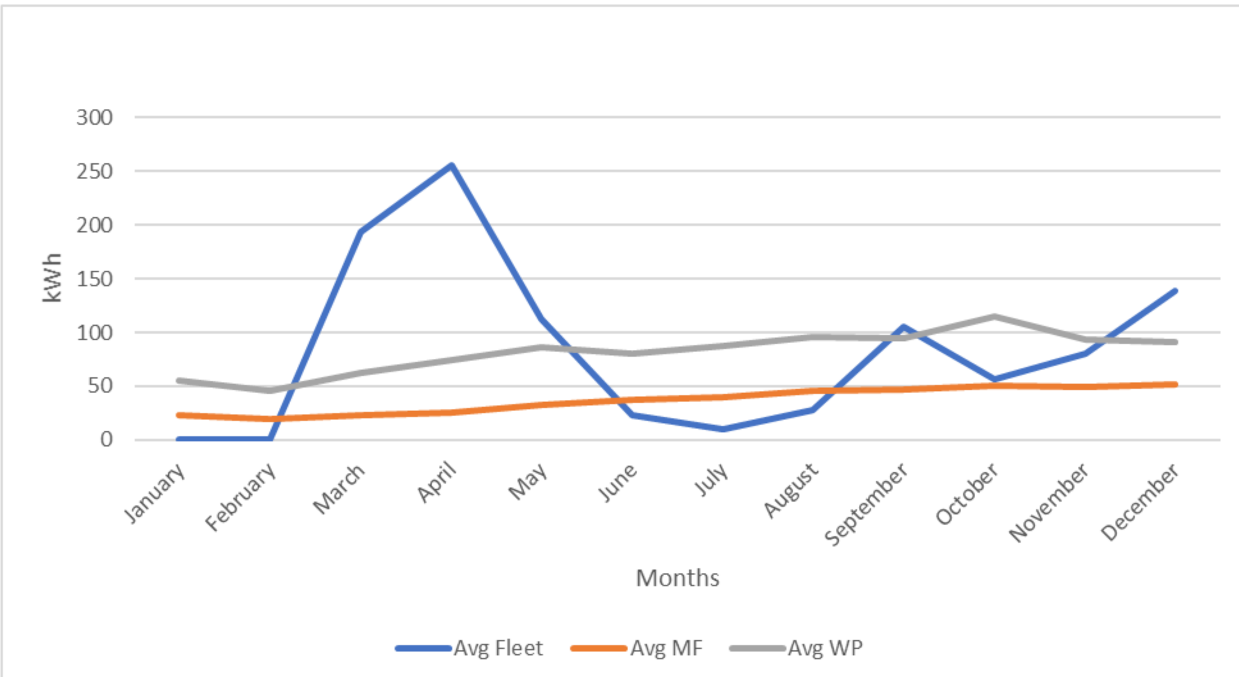
In SDG&E Chart 11a, the average port consumption per month for 2019 shows a few spikes in the Fleet segment around the months of March and April. These were caused by charging station testing during that time. A few months later, the station count almost doubled but the energy consumed was still approximately the same. This caused the average to drop slightly. The second spike in Fleet consumption is shown in September, which is due to the station count growing from 27 to 45 and the corresponding energy consumption increased by a multiple of six from approximately 690 kWh to 4200 kWh in that time period.

In SDG&E Chart 11b, the average port consumption per month for 2020 does not show similar spikes as in 2019, but it is clear that most segment types start to decline beginning in March 2020 due to the COVID-19 pandemic.

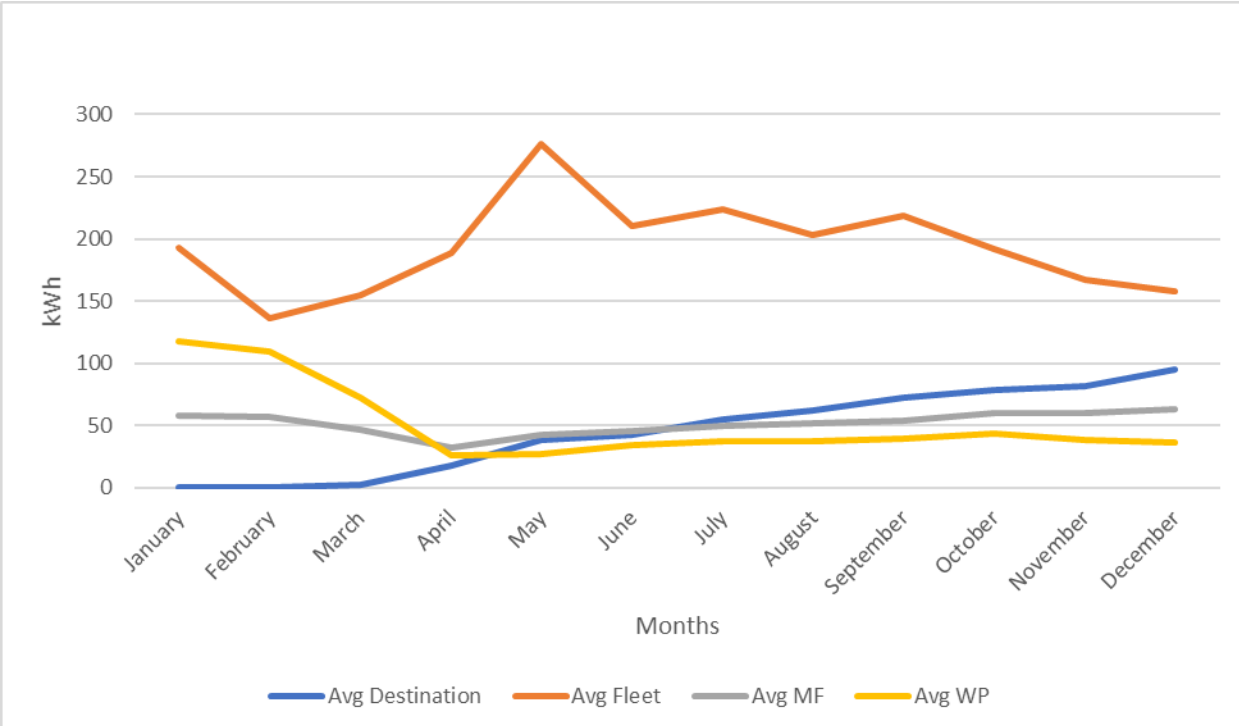
Notes: For 2019, all sites that had “testing” consumption before the stations went live had that consumption zeroed out in the data for the site so as not to skew the results.

The 2019 average hourly fleet and destination consumption graphs are higher than might be expected because there is a lower station count for those segments. For example: One site with a single port would show a higher consumption average versus a site with ten ports (and five in use) would show 50% consumption/kWh by port as compared to the single port.

SDG&E Chart 11a: 2019 Average Port Consumption Per Month



SDG&E Chart 11b: 2020 Average Port Consumption Per Month



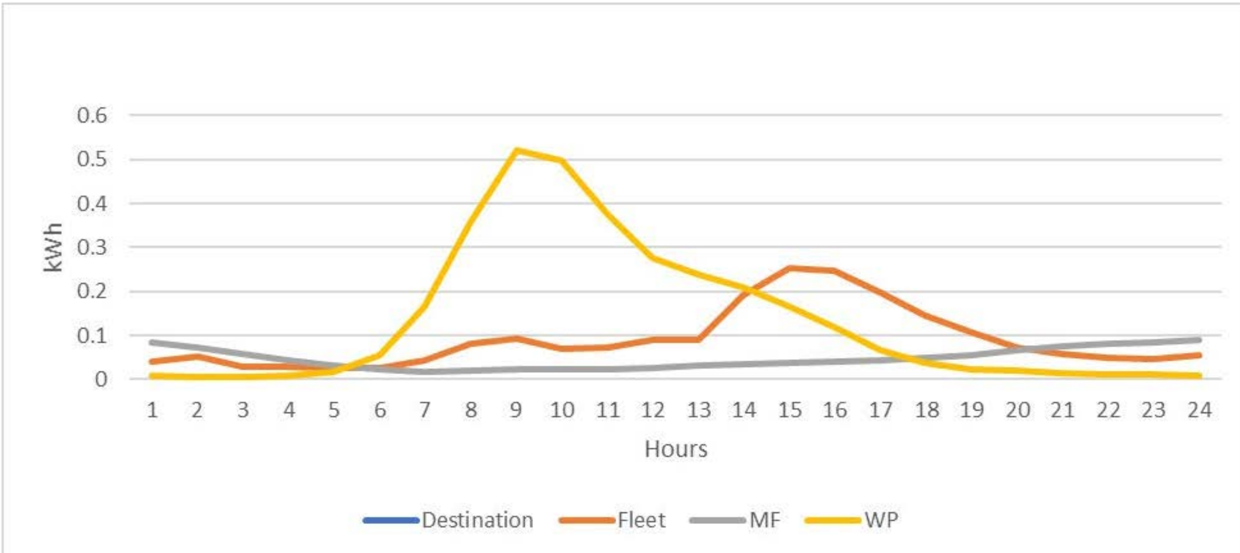
2019 Hourly Results

The 2019 hourly results were calculated by summing the total count of ports by sector at the end of each month, so the resulting load profile reflects the "typical" load profile on a given day rather than the sum of the loads across all days in the year.

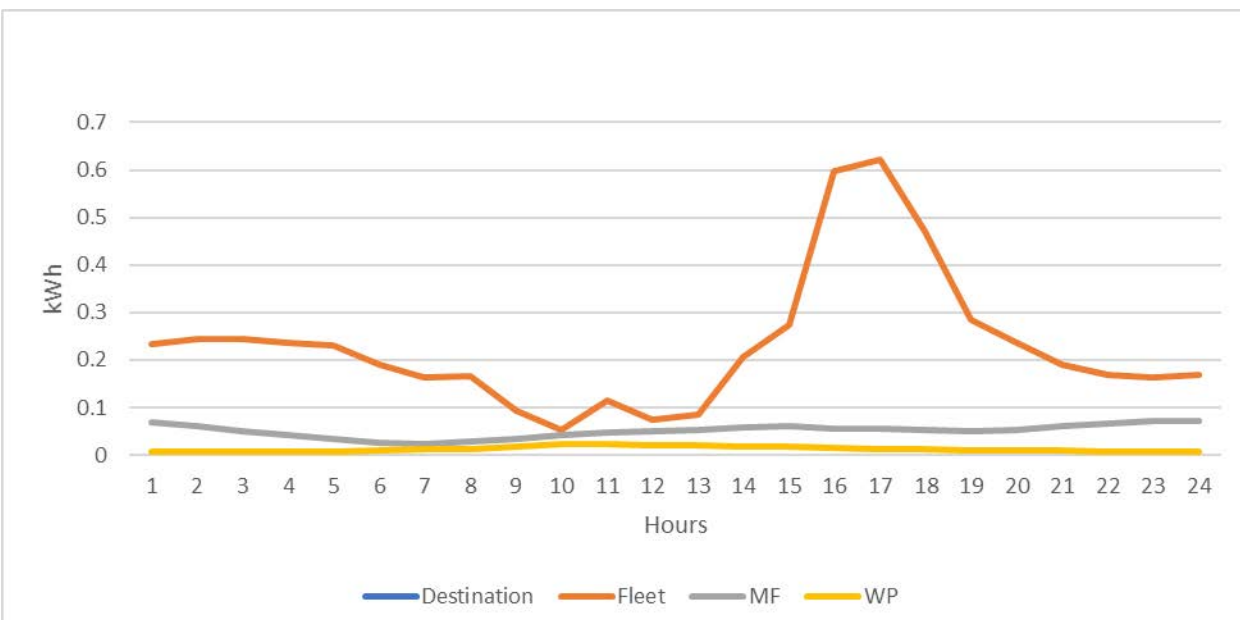
In SDG&E Chart 12a for 1999, the average weekday port consumption for all ports is shown. Note that the overall consumption is lower than might be expected because all ports are included (whether they were active or not). As shown in the chart, workplace consumption peaks from 7am to 1pm as expected in 1999.

In SDG&E Chart 12b for 1999, the average weekend port consumption for all ports is shown. Fleet charging has some activity across the hours, especially on weekend late afternoons.

SDG&E Chart 12a: 2019 Average Weekday Port Consumption For All Ports



SDG&E Chart 12b: 2019 Average Weekend Port Consumption For All Ports



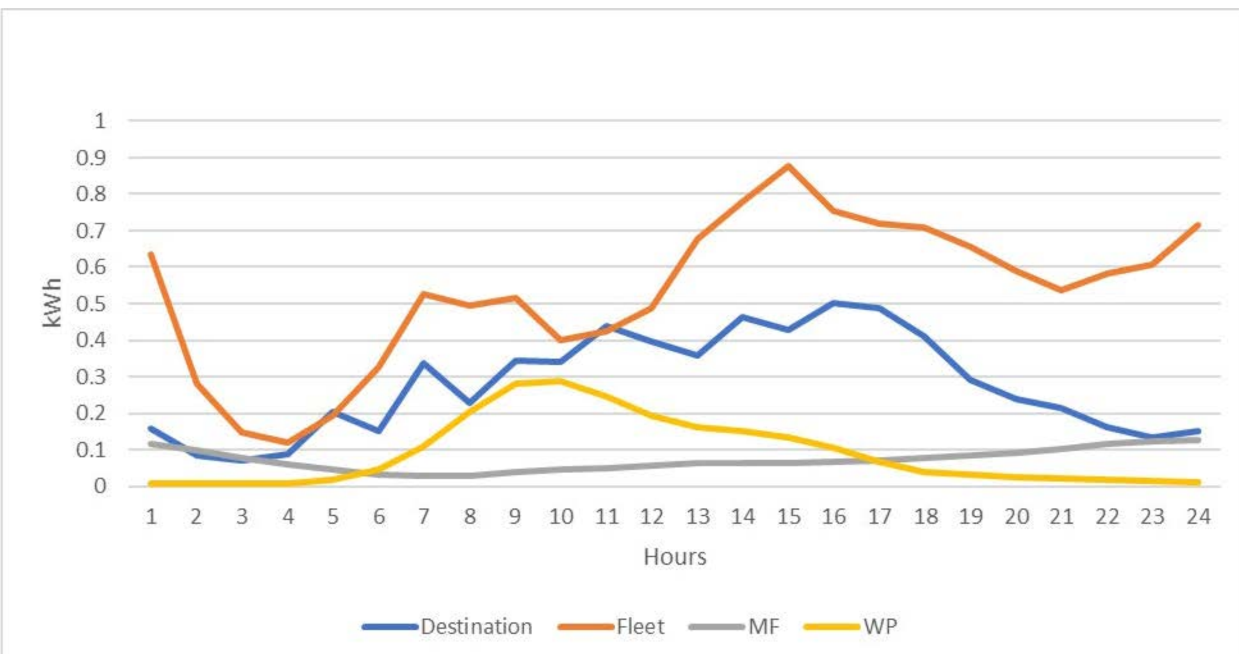
2020 Hourly Results

For SDG&E Charts 13a and 13b below, the total energy consumption per site per month was aggregated into a sum of total consumption per month per segment type. Then the average of that consumption was calculated by dividing the Total Consumption by the Total Station Count per month. Finally, the total station count per site per month data was aggregated to arrive at the total station count per month per segment type numbers.

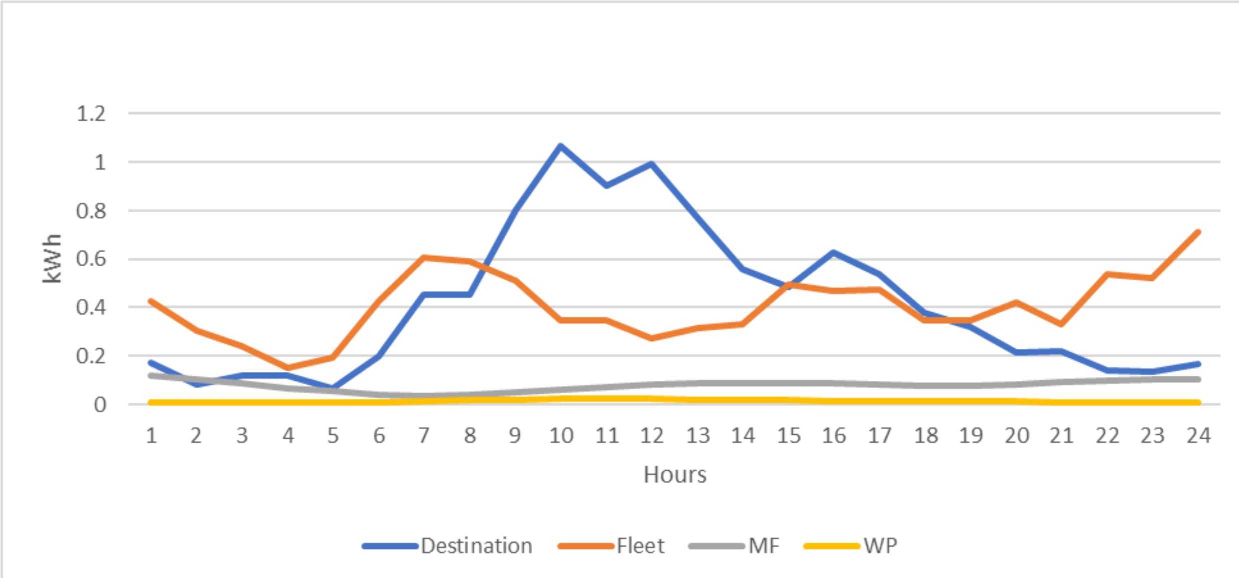
The weekday charging data for 2020 shown in SDG&E Charts 13a is fairly straightforward without any notable trends. The weekend charging data, however, for 2020 in SDG&E Charts 13b shows that destination charging went live in 2020 with notable activity in the morning (9am) and early afternoons (1pm).

As expected, workplace sites in 2020 show less charging activity than 2019 on weekends.

SDG&E Chart 13a: 2020 Average Weekday Port Consumption For All Ports



SDG&E Chart 13b: 2020 Average Weekend Port Consumption For All Ports



IV. Cost Tracking Data

A. Overview and Approach

This report provides aggregated EV Charging Infrastructure cost data, by IOU. The IOUs have coordinated, to the extent possible, to provide consistency in data assumptions. However, because utilities have different methods of tracking their costs, the costs calculated for each category may be based on different assumptions. Each IOU section includes information on the general approach and assumptions for the cost data; it also explains why certain data may not be available at this time.

Additionally, this report is limited, in that it primarily includes utility-incurred costs. Traditionally, customer-side costs (behind the meter) are generally unknown to the utility unless covered by a utility TE program. As such, certain customer costs, which may be required for deploying EV infrastructure but unknown to the utility, may not be accounted for in this report. One example of this type of cost is the trenching and site excavation for service line extensions, costs that are not utility service facilities under Rules 15 and 16 and are therefore borne by customers and not tracked by the utility. Such costs are not included in this report.

Table 1 below provides a summary of the EV infrastructure costs and responsibilities, for projects outside of an IOU EV charging infrastructure program. Comparing the costs of installing EV charging infrastructure by IOU TE programs and traditional delivery (or non-program) is challenging, as the IOUs are unable to track and report on all non-program customer costs. This report includes information on those costs that are known to the IOUs.

Table 1: Summary of EV Infrastructure Costs and Responsibilities

	Customer Assigned Costs	Allowance?	Utility Assigned Costs
Equipment on Customer Side of Meter	Customer pays all costs for charging equipment, including costs to plan, design, install, own, maintain, and operate facilities and equipment beyond the Service Delivery Point		
Service Line Upgrade	• Excavation: trenching, backfilling, and other digging as required including permit fees • Furnishing, installing, owning, and maintaining all Conduits (including pulling tape) and Substructures, furnishing riser materials • Protective Structures: Furnishing, installing, owning, and maintaining all necessary Protective Structures as specified by utility for utility's facilities	Yes, to cover work responsibility assigned to utility. Customer pays amount exceeding allowance. This is in addition to Customer assigned costs. Note: CPUC policy exemption in place through December 2021 for residential upgrades when EV load is added. Under exemption, amount exceeding allowance is not paid by customer and instead paid by utility and recovered through distribution rates.	• Underground Service: service conductors and connectors • Overhead Service: conductors and support poles • Metering: meters and associated utility-owned metering equipment
Secondary Lines/ Transformer Upgrade (serving 2 or more Service Lines)			Utility pays all costs for upgrading and maintaining the distribution system. Recovered through distribution rates.

Cost data is located within Attachments 1 – 3, by IOU.[35] Attachments 1 - 3 include the following cost tables:

- Table 2: Non-Program Costs for 2020
- Table 3: Pilot-Program Costs for 2020
- Table 4: Historic Costs

The IOUs will work with the Energy Division in 2021 to continue to refine this report for the future.

[35] See Attachment 1 for PG&E data; Attachment 2 for SCE data, and Attachment 3 for SDG&E data.

B. PG&E's EV Infrastructure Cost Data

Table 2 in Attachment 1: Non-Program Costs

a. General Approach and Cost Assumptions

PG&E performed EV-related upgrade work for 81 residential charging infrastructure projects and 62 non-residential charging infrastructure projects in 2020. These only include projects that were fully invoiced during the period of January 1, 2020 through December 31, 2020 even if the project work began in 2019. Costs related to EV infrastructure installation as part of new building construction are not separately tracked and therefore not included in this report.

Upgrade costs related to EVs fall into three categories: 1) equipment on the customer side of the meter, 2) the individual customer service line, and 3) the utility distribution system that serves multiple customers. As described above, residential and non-residential customers receive an allowance for upgrade costs on the utility side of the meter and are responsible to pay any costs over the allowance. Residential EV customers are exempt and any costs above the residential allowance are assigned to the utility per current CPUC policy. PG&E does not have information on the customer side of the meter costs and limited insight on the customer assigned costs for service line upgrades, which includes costs over the Rule 16 allowance.

It is important to note that there may be differences in how non-program costs are tracked and reported across the three IOUs and therefore it is necessary to take into account the differences and caveats explained in this report when comparing the cost tables.

- **Site Costs**
    - PG&E separately estimates and records the costs of specific work types of design, trenching, separate meters, permitting, distribution system work (under Rule 15[36]), and service line work (under Rule 16[37]). In this report, PG&E includes costs for projects that were fully invoiced in 2020 and uses the following definitions for the cost categories in Table 2:
        - Design – costs for all utility side of the meter design assigned to the utility or the customer,
        - Trenching and site excavation – Costs for all work related to digging and excavation to lay conduit and wires for projects. This includes costs for work completed by the utility or the customer and assigned to the utility and customer,

[36] PG&E Electric Rule 15 - https://www.pge.com/tariffs/assets/pdf/tariffbook/ELEC_RULES_15.pdf
[37] PG&E Electric Rule 16 - https://www.pge.com/tariffs/assets/pdf/tariffbook/ELEC_RULES_16.pdf

        - Separate meter – costs for all meters purchased for all projects and assigned to the utility or customer,
        - Permitting – cost of all permits necessary for work on the utility side of the meter and assigned to the utility or customer,
        - Total Distribution System Costs Incurred by Utility for Upgrades – all costs associated with work performed on the distribution system under Rule 15 including design, trenching, permitting and other materials and labor,
        - Total Service Line Costs Incurred by Utility for Upgrades – all costs associated with work performed on the service line under Rule 16 including design, trenching, permitting, meters, and other materials and labor,
        - Total Utility side costs – all costs assigned to the utility for work associated with the EV-related upgrade including Rule 15 and Rule 16 costs, grid betterment work, the allowance and costs above the allowance for residential customers, and
        - Total Customer side costs – all costs assigned to the customer for work performed on the utility side of the meter that PG&E has insight into (e.g. service line trenching, backfilling, and other digging as required including permit fees; furnishing, installing, owning and maintaining all conduits and structures, including riser material, and all rights of way costs, if applicable). The utility or the customer may have performed the work. For residential customers this includes any cost above the allowance even though this is assigned to the utility under the CPUC policy exemption.

- **Support Activities:**
    - PG&E is able to report the project management costs associated with residential and non-residential EV-related projects as a percentage of the total construction labor.
    - Other support activity costs are not reportable and further explained in section b.
- The methodology is the same for the recording costs of both residential and commercial charging infrastructure non-program work.

b. Explanation of why certain data is unavailable to report

- For Total Customer side costs, PG&E is only able to report on costs assigned to the customer for work on the utility side of the meter that PG&E has insight into. There may be some additional costs for work on the utility side of the meter assigned to the customer that is not reported here. Total customer side costs also do not include costs for the behind-the-meter work performed by the customer.

- PG&E does not separately track ongoing maintenance or support activities, except for project management, for EV-specific work orders; those costs are part of general new business and/or customer requested modification work orders and cannot be reported for a specific subset of projects.
- PG&E has not previously tracked residential port counts and/or kilowatt (kW) amounts. This requires a change in our tracking system and project management procedures which PG&E is taking steps to implement.
- PG&E began tracking commercial port counts and/or kilowatt (kW) amounts in 2020 however the process change is too new to capture the data for 2020 projects.

c. Steps to report currently unavailable data at a later time

- PG&E is working to systematically capture residential port counts and/or kilowatt (kW) amount information for future reporting periods. The data for commercial projects will be available to report for 2021 projects.

d. Explanation of plans to provide additional data in future reports

- PG&E and the other IOUs will continue collaborating with Energy Division staff to identify other costs of interest to include in future reports, including key cost drivers that may be identified in the future.

Table 3 in Attachment 1: Pilot-Program Costs

a. General Approach and Cost Assumptions

PG&E includes costs for projects in 2020[38] across six programs – EV Charge Network (EVCN), EV Fleet, EV Fast Charge, and three Priority Review Projects (Medium-Heavy Duty Fleet Demonstration Project, Idle Reduction Project, and Electric School Bus Renewables Integration Project). EVCN fully invoiced 94 completed projects in 2020. This included 25 projects at Multi

[38] Some costs represented in Table 3 in Attachment 1 for TE Programs represent costs for projects that were fully invoiced within 2020 (which, therefore, PG&E has full insight into actual costs for); these costs may include costs incurred for projects whose design, construction, and activation timeline spanned multiple calendar years, and therefore some costs for the projects represented in this table may have been incurred in years prior to 2020. For this reason, it would not be possible to simply add costs from consecutive EV Load and Charging Cost Reports by TE Program and arrive at a mutually exclusive sum of program costs. Other costs represented in Table 3 in Attachment 1 represent those costs that were incurred within calendar year 2020 for that cost category.

Unit Dwelling (MUD) sites delivering 518 ports, and 69 sites at workplaces (WP) delivering 1,608 ports. EV Fleet fully invoiced 6 completed projects in 2020, including 5 Small Sites serving a total of 41 vehicles and 1 Medium Site serving 30 vehicles. EV Fast Charge is still in early phases of program implementation (specifically, project construction) and did not fully invoice any completed projects in 2020. The PRP projects have all been substantially completed and did not accrue additional site costs during 2020. They did report support activities costs and other costs, however.

Reported costs are not tracked in this report by individual program. Instead, costs are categorized by Light Duty Vehicle (LDV) Infrastructure and Medium and Heavy Duty (MD/HD) Infrastructure. Light Duty Infrastructure is further subcategorized by L2 residential infrastructure, L2 non-residential infrastructure, and DCFC infrastructure. All EVCN MUD sites fell within the LDV MUD category and all EVCN WP sites fell within the non-residential category. DC Fast Charge aligns with the DCFC category. Furthermore, MD/HD is segmented by the capacity a given site adds to accommodate charging equipment installations: Small – installed charging capacity adds up to 500 kW, Medium – between 500 kW and 3 MW, and Large – beyond 3MW. Among EV Fleet's 6 projects, 5 were small sites that added a total of 850 kW of new capacity, and 1 medium site that added a total of 504 kW of new capacity. PRP projects align with the small site category but did not add new infrastructure and consequently new capacity during 2020.

It is important to note that there may be differences in how program costs are tracked and reported across the three IOUs and it is necessary to take into account the differences and caveats explained in this report when comparing the cost tables.

- **Site Costs:**
    - In 2020, PG&E's site costs included projects that were fully invoiced[39] across the EVCN and EV Fleet programs. PG&E records each project's site costs and uses the following definitions for the cost categories in Table 3:
        - Design – utility costs for all final site designs for projects,
        - Trenching and site excavation – estimated costs for all utility work related to digging and excavation to lay conduit and wires for projects fully invoiced in 2020. This does not include restoration costs,

[39] Fully invoiced indicates that PG&E had full actual cost data because third-party vendor invoices were completed. This is different from "substantially completed", which for light-duty vehicle infrastructure is defined as projects where all customer side or "behind the meter" (BtM) construction work is complete (excluding charger installation), and all utility side or "to the meter" (TtM) equipment is installed (excluding to the meter wire pulls or energization). Projects substantially completed in 2020 may include projects that in 2020 had not yet completed charger installation or site restoration.

        - Separate meter – estimated total costs for all meter panels, associated equipment, and installation costs for all projects,
        - Permitting – estimated costs associated with permits and labor to apply for permits,
        - Total Utility side costs - "to the meter" construction costs (including trenching), as well as estimated materials and design costs, and
        - Total Customer side costs – "behind the meter" construction costs (including trenching), as well as estimated materials, design, and permitting costs but excluding charger costs, participation payments, and rebates where applicable.
    - The categorization is generally the same for the recording of Light Duty and Medium- and Heavy-duty site costs.
    - "Site Costs" do not include project management costs and rebates.
    - The specific site costs of design, trenching, separate meters, and permitting are a subset of the total utility side costs and total customer side costs reported for projects fully invoiced in 2020.
- **Support Activities Costs**
    - Support Activities costs are reported for work done in the 2020 calendar year and are in many cases not tracked to specific project sites[40]. In 2020, PG&E Support Activities costs included reported costs for all programs. PG&E uses the following definitions for the cost categories in Table 3:
        - Project management – all labor costs associated with project management for projects fully invoiced[41] during 2020,
        - Customer outreach – all costs associated with customer outreach before contract was signed on any given project, with reported costs representing spend in this category in 2020,

[40] A portion of project management costs are associated with the specific projects fully invoiced in 2020. Some project management costs and the remaining two support activities cost categories are not directly associated with projects fully invoiced in 2020 (i.e. these could include projects that were worked on in 2020 but not fully invoiced in 2020).
[41] See footnote 33.

        - Outreach and education materials – all material costs for program marketing, including collateral, website development, and events spent in 2020, and
        - Other costs – these include rebates for various programs and non-capital costs related to software and hardware integration for the Medium/Heavy Duty Customer Fleet Demonstration Pilot.

b. Explanation of why certain data is unavailable to report

Some cost data from the programs was not available to report. There are different reasons depending on the cost category, and it may also vary between programs. PG&E provides detail on some of the specific data that is unavailable to report below:

- Light Duty Vehicle Infrastructure
    - Design, permitting, and trenching costs are recorded as part of broader cost categories. As a result, these costs have been estimated using contractor submission data.
    - Additionally, design, materials, overheads, and permitting costs are not separately recorded for utility side work and customer side work. As such, the provided costs are prorated between utility side costs and customer side costs based on estimated utility side vs customer side construction labor allocations.
    - In other instances, costs are not consistently separately recorded for each project site in a way that is easily aggregated, and often require manual tabulation/estimation for Light Duty Vehicle Infrastructure, e.g.:
        - Separate meter costs are estimated based on the number of meter panels installed at each project site and an estimated unit price for meter panels, associated equipment, and installation costs.
        - Permitting costs are estimated based on the costs of the labor to apply for the permit, and the permit costs.
    - Site costs for "DCFC-LDV" would only capture PG&E's EV Fast Charge program. EV Fast Charge had no sites that were fully invoiced by December 2020.
- Medium and Heavy-Duty Vehicle Infrastructure
    - Site costs include only to-the-meter costs as there was no infrastructure construction behind the meter in projects fully invoiced in 2020.
    - PG&E is able to report total number of sites installed but not total number of ports installed. This is due to design of the program as approved by the Decision

on the Transportation Electrification of Standard Review Projects[42] where PG&E has vehicle and site targets.

- PG&E does not separately record distribution system upgrade costs or service line upgrade costs related to EV infrastructure installation through programs. Costs incurred to the utility for any work on the distribution system or service line in the programs are considered to-the-meter costs and are captured under total utility side costs.

c. Steps to report currently unavailable data at a later time

- PG&E is working to be able to provide more granular cost actuals for permitting, trenching, and separate meters for infrastructure constructed in 2021 for certain programs[43] by revising the process and structure of contractors' cost reporting and invoicing and tracking those specific cost components through new software tools. This additional data may be included in future reports.

- EV Fleet tracks sites and vehicles as directed by the Decision, not ports. As a result, PG&E's tracking system was designed and structured to meet these requirements.

d. Explanation of plans to provide additional data in future reports

- PG&E and the other IOUs will continue collaborating with Energy Division staff to identify other costs of interest to include in future reports, including key cost drivers that may be identified during program deployment.

<u>**Table 4 in Attachment 1: Historic Costs**</u>

a. General Approach and Cost Assumptions

- **Non-program Charging Infrastructure costs:**
    - Historic non-program residential charging infrastructure costs from 2011-2018 are pulled from data used in previous Load Research Reports and 2019 costs are pulled from the EV Infrastructure Cost Report submitted in 2020.
        - The process to report utility distribution and service line costs for this Report is different than for previous Load Research Reports and may make a comparison between tables challenging.

[42] D.18.05.040: https://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442457637
[43] Excludes EVCN, for instance.

- Historic non-program commercial charging infrastructure costs were first included for 2019 projects and the data is pulled from Table 3 in Attachment 1 of the EV Infrastructure Cost Report filed on April 1, 2020.
- Historic program infrastructure costs were first included for 2019 projects and the data is pulled from Table 2 in Attachment 1 of the EV Infrastructure Cost Report filed on April 1, 2020.
- As mentioned in the section on Table 2 of attachment 1, upgrade costs related to EVs fall into three categories: 1) equipment on the customer side of the meter, 2) the individual customer service line, and 3) the utility distribution system that serves multiple customers.
- PG&E does not have information on the customer side of the meter costs nor insight on all the customer assigned costs for service line upgrades.
  - The Customer pays all costs for beyond the Service Delivery Point.
  - The Customer is responsible for trenching, backfilling, and other digging as required including permit fees.
  - The Customer is responsible for furnishing, installing, owning and maintaining all conduits and structures, including riser material.
  - The Customer is responsible for all rights of way costs, if applicable.
- Per the CPUC policy exemption currently in place, when the Rule 16 costs exceed the allowance provided for residential EV service line upgrades, the amount exceeding the allowance is not paid by the customer, but instead by PG&E (recoverable through distribution rates).

b. Explanation of why certain data is unavailable to report

- N/A

c. Steps to report currently unavailable data at a later time

- N/A

d. Explanation of plans to provide additional data in future reports –

- PG&E will work with Energy Division and the other IOUs to determine how future historical (i.e. reporting periods 2019 and beyond) will be organized on future reporting templates.

C. SCE's EV Infrastructure Cost Data

Table 2 in Attachment 2: Non-Program Costs

a. General Approach and Cost Assumptions

In addition to SCE's TE programs and pilot activities, SCE completed Non-Program, EV-related infrastructure work for 29 residential charging infrastructure projects and 80 non-residential charging infrastructure projects in 2020. SCE is only reporting on projects, for which construction was completed between January 1, 2020 and December 31, 2020. Regardless of the year the project originated, all costs associated with a project completed in 2020 are included in this report. Costs related to EV infrastructure installation conducted as part of new building construction are not separately tracked and therefore not included in this report.

Non-program infrastructure costs related to EVs fall into three categories: (1) the utility distribution system that serves multiple customers (Rule 15), (2) the individual customer service line (Rule 16), and (3) equipment on the customer side of the meter (behind the meter). Behind the meter costs related to EV infrastructure installation, which are not specific to a TE pilot or program, are not tracked by the utility and therefore are not included in this report. In this report, EV infrastructure is accounted for only if a work order is opened and identified as an EV work order. The cost reporting methodology is the same for the recoding of costs for both residential and commercial charging infrastructure nonprogram work.

Residential and non-residential customers receive an allowance for upgrade costs on the utility side of the meter. Customers are responsible to pay any costs over the allowance. Per the CPUC Administrative Law Judge's Ruling issued on November 23, 2020, in Rulemaking 18-12-006, all residential service facility upgrade costs in excess of the residential allowance required to accommodate Basic Plug-In-Hybrid and Electric Vehicle Charging Arrangements shall be treated as common facility costs rather than being paid for by the individual plug-in hybrid and electric vehicle customer until December 31, 2021.

There are differences in how non-program costs are tracked and reported across the three IOUs and it is necessary to take into account the differences and caveats explained in this report when comparing the cost tables.

- **Site Costs**
    - If applicable, SCE separately estimates and records the costs of specific types of work including trenching, separate meters, permitting, distribution system work (Rule 15), and service line work (Rule 16). In this report, SCE includes costs for projects where construction was completed in 2020 and uses the following definitions for the cost categories in Table 2:
        - Trenching and site excavation – costs, if performed by the utility, for all work related to digging and excavation to lay conduit and wires for projects.

  - Separate meter – an average cost for a meter based on customer rate schedule is used to calculate total cost per meter. SCE generally purchases its meters in bulk, rather than for individual work orders. Actual meter costs are recorded in mass plant and capitalized when received.
  - Permitting – cost of all permits necessary for work on the utility side of the meter.
  - Total Distribution System Costs Incurred by Utility for Upgrades – all costs associated with work performed on the distribution system under Rule 15 including trenching, permitting and other materials and labor.
  - Total Service Line Costs Incurred by Utility for Upgrades – all costs associated with work performed on the service line under Rule 16 including trenching, permitting, meters, and other materials and labor.
  - Total Utility side costs – all costs assigned to the utility for work associated with the EV-related upgrade including Rule 15 and Rule 16 costs.
  - Total Customer side costs – all costs invoiced to and paid by the customer for work performed on the utility side of the meter that SCE has insight into (e.g., riser material, all rights of way costs, and tax, if applicable).
  - For residential customers this also includes any cost above the allowance even though this is assigned to the utility under the CPUC policy exemption.

- **Support Activities**

  The non-program support activities include project management, outreach, and marketing and education. SCE does not conduct marketing and education or outreach for non-program related EV charging infrastructure activities, and therefore does not have costs for these activities. While program management activities are conducted, SCE does not have a separate program management function and is not able to separate out these costs for reporting.

- **Other Support Activity**

  SCE does not have "other support" activities for which to report.

b. Explanation of why certain data is unavailable to report

- SCE is not able to separately track utility-side design costs; those costs are part of general new business and/or customer requested modification O&M expense and cannot be reported for specific projects.
- For Total Customer side costs, that are non-program related, SCE is only able to report on costs assigned to the customer for work on the utility side of the meter, for which SCE has visibility. There may be some additional costs for work on the utility side of the meter assigned to the customer that are not reported here. In addition, total customer side costs do not include costs for the behind-the-meter work performed by the customer.
- While program management activities are conducted, SCE does not have a separate program management function and is not able to separate out these costs for reporting.
- SCE is not able to separately track projected ongoing maintenance costs for utility-side infrastructure.
- SCE has not previously tracked residential or commercial port counts and/or residential kilowatt (kW) amounts. This requires a change to our tracking system which SCE is taking steps to implement.

c. Steps to report currently unavailable data at a later time

- SCE does not yet have the ability to capture information on residential or commercial port counts and/or residential kW amounts but is continuing to explore ways to systematically capture this information for future reporting periods.

d. Explanation of plans to provide additional data in future reports

- SCE and the other IOUs will continue collaborating with Energy Division staff to identify other costs of interest to include in future reports, including key cost drivers that may be identified in the future.

<u>Table 3 in Attachment 2: Pilot-Program Costs</u>

a. General Approach and Cost Assumptions

SCE is providing costs for its TE pilots and programs that were invoiced or recorded in 2020. As such, SCE's TE pilot and program costs may include costs for projects that were completed in 2019 but invoiced in 2020, in addition to projects completed in 2020. The light-duty vehicle (LDV) programs that incurred costs in 2020 include Charge Ready Pilot & Bridge, Charge Ready DCFC Pilot, Charge Ready Schools (AB 1082), and Charge Ready Parks & State Beaches (AB 1083). The medium- and heavy-duty vehicle (MDHD) programs that incurred costs in 2020 include Charge Ready Transport, Charge Ready Transit Pilot, and Port of Long Beach Rubber Tire Gantry. In 2020, SCE Light-Duty Vehicle Infrastructure completed construction at 26 Multi-Unit Dwellings projects with 310 ports and 35 Non-Residential projects with 1,132 ports. Within the

Medium- & Heavy-Duty Vehicle Infrastructure segment, SCE completed construction at 5 small sites with 22 ports and 1 medium site with 12 ports. SCE tracks MDHD program goals based on vehicles electrified and not based on port count. As such, there were 48 MDHD vehicles electrified for 5 small sites and 30 MDHD vehicles electrified at the 1 medium site.

SCE records each project's site costs in separate work orders for:

- Utility-side costs ("to the meter" capital labor and contract construction costs, including design, trenching, permitting, etc.) and
- Customer-side costs ("behind the meter" capital labor and contract construction costs, from the meter to the stub-out for the charging equipment, design, trenching, permitting, etc.)

The methodology is the same for the recording of Light-, Medium- and Heavy-duty, and Priority Review Projects (Port of Long Beach and Transit Bus) construction costs. This methodology will also be consistent with the Charge Ready Schools (AB 1082) and Charge Ready Parks and State Beaches (AB 1083).

- **Site costs** – Includes only Capital costs.
    - Design costs, trenching and site excavation, and permitting costs provided in the Site Costs section are only customer-side costs. These costs are estimates based on overall program allocations.
        - Design costs - SCE is able to provide these customer-side costs in 2020 due to the implementation of third-party contracts with Architecture and Engineering firms for design work.
        - Trenching and site excavation – Customer-side costs charged by our general contractors for trenching, site excavation, and restoration.
        - Permitting costs –Starting in 2020, SCE is able to capture permitting costs.
    - Separate meter costs are provided for only projects that were completed in 2020. An average cost for a meter based on customer rate schedule is used to calculate total cost per meter. SCE generally purchases its meters in bulk, rather than for individual work orders. Actual meter costs are recorded in mass plant and capitalized when received. Meter costs are not recorded against program budget.
    - Total Utility-side costs are all actual costs charged to the "to the meter" Work Orders and separated based on the report groupings into their respected Light-Duty and Medium- & Heavy-Duty categories.
    - Total Customer-side costs are the sum of design costs, trenching and site excavation, and permitting costs.

- **Support Activities** – Includes both Operation and Maintenance "O&M" and Capital expenses

  - Other cost includes rebates, canceled project costs, capital IT implementation costs, and test equipment for the Charge Ready Parks and State Beaches program.

- **Other Support Activity**
  - Provides total number of charge ports installed for projects completed in 2020. Amount of new capacity resulting from project (kW) is calculated based on total number of ports multiplied by the maximum power output for the equipment that were installed at the project location.

b. Explanation of why certain data is unavailable to report

- SCE is not able to separately track utility-side design costs; those costs are part of general new business and/or customer requested modification O&M expense and cannot be reported for specific projects. SCE accounting is not able to break down utility-side site excavation and trenching, and permitting costs into separately recorded entries. As such the totals indicated in Attachment 2 Table 3 for design, site excavation and trenching, and permitting are only for customer-side costs, which are estimated based on overall program allocations.
- SCE is not able to separately record distribution system upgrade costs or service line upgrade costs related to EV infrastructure installations.
- SCE is not able to track projected ongoing maintenance costs for utility-side infrastructure as part of its program costs.
- SCE's large sites "Large Sites: >3 MW" include only utility-side costs, with no O&M or customer-side cost component.

c. Steps to report currently unavailable data at a later time

- SCE has taken steps to ensure more detailed tracking of costs by creating separate work orders per site for utility-side costs, customer-side costs, and easements. Within these work orders, SCE uses cost elements, cost descriptions, and purchase order information to further breakdown costs into additional subcomponents. An example of steps taken from 2019 to 2020 include new contracts to provide actuals for permitting and design for customer-side costs.
- SCE will continue to review our current capital reporting structure and look for ways to improve cost recording to separate site excavation and trenching costs for both utility and customer side.

d. Explanation of plans to provide additional data in future reports –

- SCE plans to work with the Energy Division to refine this report for the future, and as part of that process will consider how to best capture the data needs requested.

Table 4 in Attachment 2: Historic Costs

a. General Approach and Cost Assumptions

- Years 2011-2018 historic residential costs are pulled from data used in previously submitted Load Research Reports.
    - The template to report utility distribution and service line costs for this Report is different than for previous Load Research Reports and may make a comparison between tables challenging.
- Year 2019 historic costs are pulled from data provided in the previously submitted 2020 EV Charging Infrastructure Cost Report.[44]
- As mentioned previously, upgrade costs related to EVs fall into three categories: 1) equipment on the customer side of the meter, 2) the individual customer service line, and 3) the utility distribution system that serves multiple customers. In this report, EV infrastructure is accounted for only if a work order is opened and identified as an EV work order.
- For non-program EV charging infrastructure, SCE does not have information on the customer side of the meter costs nor insight on the customer assigned costs for service line upgrades.
    - The Customer pays all costs for beyond the Service Delivery Point.
    - The Customer is responsible for trenching, backfilling, and other digging as required including permit fees.
    - The Customer is responsible for furnishing, installing, owning and maintaining all conduits and structures, including riser material.
    - The Customer is responsible for all rights of way costs, if applicable.
- Per the CPUC policy exemption currently in place through December 31, 2021, when the Rule 16 costs exceed the allowance provided for residential EV service line upgrades, the amount exceeding the allowance is not paid by the customer, but instead by SCE (recoverable through distribution rates).

b. Explanation of why certain data is unavailable to report

- N/A

c. Steps to report currently unavailable data at a later time

- N/A

[44] *See* Attachment 2, Table 4, Note 2.

d. Explanation of plans to provide additional data in future reports –

- SCE will work with Energy Division and the other IOUs to determine how future historical (I.e., reporting periods 2019 and beyond) will be organized on future reporting templates.

D. SDG&E's EV Infrastructure Cost Data

Table 2 in Attachment 3: Non-Program Costs

a. **General Approach and Cost Assumptions**

- Costs provided are direct costs, overheads, and AFUDC incurred in 2020 for completed sites during the year.
- Total Customer costs include excess of allowance that is due, or would be due, to the utility.

b. **Explanation of why certain data is unavailable to report**

- The design, permitting, trenching and site excavation costs provided are not separately tracked as a part of SDG&E's accounting information system.

c. **Steps to report currently unavailable data at a later time**

- N/A

d. **Explanation of plans to provide additional data in future reports**

- N/A

Table 3 in Attachment 3: Pilot-Program Costs

a. General Approach and Cost Assumptions

- Costs provided are direct costs, overheads, and Allowance for Funds Used During Construction (AFUDC) incurred in 2020 for sites completed during the year.
- SDG&E does not have any rebate costs for our approved infrastructure programs for sites completed in 2020.

b. Explanation of why certain data is unavailable to report

- SDG&E is not able to report separately on meter costs as they are recorded in mass plant and capitalized when they are delivered to the warehouse. Meters are not recorded in project-specific work orders.
- Permitting costs are not tracked separately and are generally included in the construction contractor and/or 3rd party engineering design support scope of work. included. Permitting costs vary by local jurisdiction but are approximately $1,000 per site based on prior programs.

- All construction costs are included in the utility side costs. SDG&E has not historically tracked utility side costs and customer side costs separately. SDG&E solicits fixed bids for combined utility and customer side costs per site. Bids for each site may be awarded individually or as bundled packages.
- SDG&E does not separately record distribution line extension costs or service extension costs related to EV infrastructure installation.
- SDG&E does not track projected ongoing maintenance costs for utility-side infrastructure as a part of its pilot program costs.
- Costs for SDG&E's Medium Duty / Heavy Duty (MD / HD) program (Power Your Drive for Fleets) and AB1082/1083 programs (Power Your Drive for Schools, Parks, and Beaches) are not available yet as no construction sites were completed in 2020.

c. Steps to report currently unavailable data at a later time

- N/A

d. Explanation of plans to provide additional data in future reports

- SDG&E will report utility side costs versus customer side costs for recently approved programs once sites are completed.

<u>**Table 4 in Attachment 3: Historic Costs**</u>

a. **General Approach and Cost Assumption**

- Costs provided are direct costs, overheads, and AFUDC incurred for completed sites during the year.
- SDG&E pays all costs for upgrading and maintaining the distribution system when residential EV load is added (recoverable through distribution rates).
- Per the CPUC policy exemption currently in place through December 31, 2020, when the Rule 16 costs exceed the allowance provided for residential EV service extensions, the amount exceeding the allowance is not paid by the customer but instead by SDG&E (recoverable through distribution rates).
- The Customer pays all costs for beyond the Service Delivery Point.
- The Customer is responsible for trenching, backfilling, and other digging as required including permit fees.
- The Customer is responsible for furnishing, installing, owning and maintaining all conduits and structures, including riser material.
- The Customer is responsible for all rights of way costs, if applicable.
- The EV infrastructure is accounted for only if a work order is opened and identified as an EV work order.

b. Explanation of why certain data is unavailable to report

- N/A

c. Steps to report currently unavailable data at a later time

- N/A

d. Explanation of plans to provide additional data in future reports

- SDG&E will work with the Energy Division staff and the other IOUs to determine how future historical data will be organized and reported in future reports / templates.

ATTACHMENT 1

V. Attachment 1 – PG&E

PG&E

Table 1: Number of EVs forecasted In IOU Service Territory

		Light-Duty	Medium/ Heavy Duty
Actual[1]	2011	2,985	
	2012	10,802	
	2013	28,414	
	2014	54,267	
	2015	81,346	
	2016	111,355	
	2017	150,890	
	2018	217,080	
	2019	274,636	
	2020	320,550	485
Forecasted[2]	2021	332,083	732
	2022	386,528	1,090
	2023	457,989	1,697
	2024	554,276	2,719
	2025	689,947	4,448
	2026	879,757	7,317
	2027	1,133,368	11,832
	2028	1,459,495	18,566
	2029	1,857,746	28,097
	2030	2,322,661	40,898

Notes:

[1] Actual LDV values are provided by the Electric Power Research Institute ("EPRI") on annual light-duty vehicle sales, based on third part registration data. Light Duty reflect cumulative annual EV sales. Medium/Heavy Duty reflect vehicles-in-operation, however there is significant general uncertainty about the number of MHD vehicles in operation in CA.

[2] Forecasted values from PG&E's 2021 EV adoption forecast (Jan 2021). PG&E’s light-duty (Classes 1-2a), medium and heavy-duty (Classes 2b-8) electric vehicles long-term forecast derives from PG&E’s market and policy driven probabilistic EV model. The model integrates different scenarios meeting state’s Zero-Emission goals (e.g. SB1014, Gov. Brown’s EO-B-48-18, Gov. Newsom's EO-N-79-20). PG&E’s 20-year forecast predicts electric vehicle population by class and segment (including rideshare vehicles), energy demand and hourly capacity forecast. It tracks electric vehicle sales in California (source: EPRI), market trends (source: BNEF, others) and includes current programs and regulations (CARB, CPUC, CEC). PG&E’s leverages internal data and results from pilot programs directed by state agencies and conducted in collaboration with other IOUs and vehicle manufacturers. PG&E's EV adoption forecast is subject to variables and assumptions regarding EV market demand, evolution and development that are outside PG&E's control and therefore the forecast is subject to significant uncertainty and should not be relied upon as point estimates for policy or planning

PG&E

Table 2: Non-Program Costs

2020 EV-related Upgrade Costs		Residential Charging Infrastructure	Non-pilot/program Commercial Charging Infrastructure
Site Costs ($)	Design costs	$110,714	$209,352
	Trenching and site excavation	$104,738	$4,554,945
	Separate meter costs	$705	$128,186
	Permitting costs	$23,033	$42,300
	Total Distribution System Costs Incurred by Utility for Upgrades	$1,276,087	$4,666,935
	Total Service Line costs Incurred by Utility for Upgrades	$12,131	$2,995,474
	Total Utility side costs	$1,297,670	$19,012,727
	Total Customer Costs	$18,364	$4,460,195
	Projected ongoing maintenance costs for utility-side infrastructure		
Support Activities ($)	Project management	$53,107	$96,231
	Customer outreach (labor)		
	Marketing and education materials		
	Other costs		
Other	Total number of charge ports installed		
	Amount of new capacity resulting from project (kW)		

Key:	
	Data not available to report
	Data not available to report for 2020, but utilities have begun tracking for future reports

PG&E

Table 3: Pilot-Program Costs

2020 EV-related Upgrade Costs		Pilot/Program Commercial Charging Infrastructure					
		Light Duty Vehicle Infrastructure			Medium and Heavy Duty Vehicle Infrastructure[3]		
		L2 Chargers - Multi-Unit Dwellings	L2 Chargers - Non-Residential LDV	DCFC - LDV [2]	Small sites: <500 kW	Medium Sites: 500 kW - 3 MW	Large Sites: >3 MW
Site Costs ($)	Design costs[1]	$617,468	$1,841,773	$0	$83,123	$20,487	$0
	Trenching and site excavation	$1,671,765	$5,973,466	$0	$241,965	$50,381	$0
	Separate meter costs	$710,000	$1,780,000	$0	$0	$0	$0
	Permitting costs	$188,303	$561,667	$0	$0	$0	$0
	Total Distribution System Costs Incurred by Utility for Upgrades						
	Total Service Line costs Incurred by Utility for Upgrades						
	Total Utility side costs	$2,325,422	$7,667,005	$0	$853,701	$189,985	$0
	Total Customer side costs	$5,945,982	$21,429,184	$0	$0	$0	$0
	Projected ongoing maintenance costs for utility-side infrastructure	$155,580		$0	$0	$0	$0
Support Activities ($)	Project management	$1,993,545		$0	$546,351	$13,110	$0
	Customer outreach (labor)	$83,689		$125,221	$1,954,245		$0
	Marketing and education materials	$202,135		$24,022	$1,343,000		$0
	Other Costs	$961,975		-	$574,798		-
Other	Total number of charge ports installed[4]	518	1,608	-	5	1	-
	Amount of new capacity resulting from project (kW)	3,471	10,774	-	850	504	-

Key:	
(grey)	Data not available to report

Notes:

[1] Design costs include only Final Design costs for 2020 Fully Invoiced projects.

[2] Any site that has a DCFC, even if L2 chargers are also installed, will be captured in this DCFC group

[3] Medium and Heavy duty infrastructure is categorized by site size based on amount of new capacity resulting from each project

[4] Medium and Heavy Duty numbers show number of sites, not ports.

PG&E

Table 4: Historic Costs Summary

	2011-2012	2012-2013	2013-2014	2014-2015	2015-2016	2016-2017	2017-2018	2019[2]
Non-Pilot/program Residential Charging Infrastructure[1]								
Total Distribution System Costs Incurred by Utility for Upgrades	$282,719	$598,172	$1,476,647	$798,367	$404,236	$1,734,016	$927,375	$0
Total Service Line Costs Incurred by Utility for Upgrades	$39,924	$69,380	$103,259	$41,377	$37,500	$27,706	$52,349	$10,137
Total Customer Portion of Utility Costs Covered by the exemption	$9,226	$34,125	$76,046	$19,669	$3,856	$3,983	$29,618	$5,649
Non-Pilot/Program Commercial Charging Infrastructure								
Total Distribution System Costs Incurred by Utility for Upgrades								$757,669
Total Service Line costs Incurred by Utility for Upgrades								$1,798,229
Pilot/Program Commercial Charging Infrastructure								
Total Utility Side Costs								$8,125,916
Total Customer Side Costs								$19,699,909

Notes:

[1] Historical upgrade costs are from data from previously submitted Load Research Reports. The data for the 2011 - 2012 report is from July 2011 through Oct 2012. The data for the next five reports and ending with the 2016-2017 report includes data from Nov - Oct of the following year. Data for the 2017-2018 report includes data from Nov 2017 through Dec 2018. The data for 2019 shows data for January-December of 2019.

[2] Details on the 2019 historical costs can be found in the EV Infrastructure Cost Report that was filed on April 2, 2020.

ATTACHMENT 2

VI. Attachment 2 - SCE

SCE

Table 1

Number of EVs forecasted In IOU Service Territory

		Light-Duty	Medium/ Heavy Duty
Actual	2011	1,736	
	2012	8,526	
	2013	21,896	
	2014	39,890	
	2015	58,908	
	2016	83,186	
	2017	114,738	
	2018	163,869	
	2019	210,620	
	2020	251,584	
Forecasted	2021	326,886	969
	2022	398,801	1,836
	2023	500,847	3,386
	2024	628,491	5,789
	2025	741,619	9,120
	2026	875,111	13,358
	2027	1,061,315	18,387
	2028	1,252,352	24,027
	2029	1,477,775	29,730
	2030	1,743,775	39,162

SCE Comments:

- Actual LDV values are provided by the Electric Power Research Institute ("EPRI") on annual light-duty vehicle sales, based on third party registration data. Please note that there is a slight revision on historical number of light duty electric vehicles provided by EPRI.

-SCE's forecasts for light-duty, medium and heavy-duty electric vehicles reflect a forecast that more closely aligns with expected decarbonization funding, mandates, and support policies. Policies such as states 5 million zero-emission vehicles goals on the roads in California by 2030 for light duty and CARB's Innovative Clean Transit and Advanced Clean Trucks rules for medium/heavy duty and buses were considered. The previous forecast assumes the high electrification target levels that the state will have to achieve in meeting its aggressive long-term decarbonization goals and it is based on SCE's Clean Power and Electrification Pathway analysis. The updated EV forecast assumes currently expected decarbonization funding, mandates, and support policies which lead to a lower level of EV adoption based on SCE's policy impact analysis.

SCE

Table 2: Non-Program Costs

	2020 EV-related Upgrade Costs	Residential Charging Infrastructure	Non-pilot/program Commercial Charging Infrastructure
Site Costs ($)	Design costs		
	Trenching and site excavation	$0	$654,415
	Separate meter costs [1]	$4,215	$22,352
	Permitting costs	$0	$44,156
	Total Distribution System Costs Incurred by Utility for Upgrades [2]	$0	$5,754,367
	Total Service Line costs Incurred by Utility for Upgrades	$14,530	$249,081
	Total Utility side costs	$18,745	$6,047,604
	Total Customer Costs [3]	$0	$251,612
	Projected ongoing maintenance costs for utility-side infrastructure		
Support Activities ($)	Project management		
	Customer outreach (labor)	$0	$0
	Marketing and education materials	$0	$0
	Other costs	$0	$0
Other	Total number of charge ports installed		
	Amount of new capacity resulting from project (kW)		36,519

Key:	
(dark grey)	Data not available to report
(light grey)	Data not available to report for 2020, but utility is researching how to track for future reports

IOU Comments:
1. Separate Meter Costs are calculated based on average meter costs by rate schedule.
2. Total Distribution System Costs incurred by the Utility for upgrades; If both distribution and service costs (Rules 15 and 16) are included in a single work order, the service costs are included in the distribution system costs total.
3. Total Customer Costs for Residential Customers is the amount of excess cost to serve that would have been billable to the customer if the current residential allowance exemption was not in place. Total Customer Costs for Commercial Customers is the amount invoiced and paid by the Customer.

SCE

Table 3: Pilot-Program Costs

2020 EV-related Upgrade Costs		Pilot/Program Commercial Charging Infrastructure					
		Light Duty Vehicle Infrastructure			Medium and Heavy Duty Vehicle Infrastructure		
		L2 Chargers - Multi-Unit Dwellings	L2 Chargers - Non-Residential LDV	DCFC - LDV [1]	Small sites: <500 kW	Medium Sites: 500 kW - 3 MW	Large Sites: >3 MW [5]
Site Costs ($)	Design costs [2]	$ 84,741	$ 463,694	$ -	$ 313,095	$ 62,619	$ -
	Trenching and site excavation [2]	$ 2,736,690	$ 10,077,484	$ 240,163	$ 514,449	$ 100,178	$ -
	Separate meter costs [3]	$ 28,455	$ 36,043	$ -	$ 4,742	$ 948	$ -
	Permitting costs [2]	$ 22,683	$ 82,267	$ -	$ 13,261	$ 2,652	$ -
	Total Distribution System Costs Incurred by Utility for Upgrades						
	Total Service Line costs Incurred by Utility for Upgrades						
	Total Utility side costs	$ 714,332	$ 2,619,899	$ 1,534	$ 453,649	$ 118,451	$ (144,416)
	Total Customer Costs	$ 2,844,115	$ 10,623,445	$ 240,163	$ 840,805	$ 165,450	$ -
	Projected ongoing maintenance costs for utility-side infrastructure						
Support Activities ($)	Project management	$ 34,056	$ 499,087	$ 39	$ 742,726	$ 148,568	$ -
	Customer outreach (labor)	$ 1,819	$ 30,629	$ -	$ 331,290	$ 66,258	$ -
	Marketing and education materials	$ 74,059	$ 273,299	$ -	$ 420,062	$ 84,012	$ -
	Other costs [4]	$ 349,783	$ 2,018,874	$ 183,386	$ 504,875	$ 381,652	$ -
Other	Total number of charge ports installed	310	1,132	-	22	12	
	Amount of new capacity resulting from project (kW)	2,232	8,150	-	777	600	

Key:	
(grey)	Data not available to report

IOU Comments:
1 Any site that has a DCFC, even if L2 chargers are also installed, will be captured in this DCFC group.
2 Only Customer-side costs separated into Design, Trenching and site excavation, and Permitting costs.
3. Meter totals are calculated based on average meter costs by rate schedule.
4. Other costs include rebates, canceled project costs, Capital IT implementation costs, and one test equipment for Parks & State Beaches.
5. Credits recorded in 2020 for unused materials recorded in 2019.

SCE

Table 4: Historic Costs Summary

	Non-Pilot/program Residential Charging Infrastructure	2011-2012	2012-2013	2013-2014	2014-2015	2015-2016	2016-2017	2017-2018	2019
Historical Upgrade Costs[1]	Total Distribution System Costs Incurred by Utility for Upgrades	$ 4,268	$ 4,863	$ 9,373	$ 17,290	$ 2,984	$ -	$ 1,845	$ 39,369
	Total Service Line costs Incurred by Utility for Upgrades	$ 26,433	$ 43,586	$ 67,627	$ 76,000	$ 44,561	$ 17,152	$ 37,538	$ 54,136
	Total Customer Portion of Utility Costs Covered by the exemption	$ 6,133	$ 12,704	$ 4,246	$ 4,885	$ 1,174	$ 375	$ 8,120	$ 511
	Non-Pilot/Program Commercial Charging Infrastructure[2]								
	Total Distribution System Costs Incurred by Utility for Upgrades								$2,814,530
	Total Service Line costs Incurred by Utility for Upgrades								$ 358,083
	Pilot/Program Commercial Charging Infrastructure								
	Total Utility Side Costs								$4,286,852
	Total Customer Side Costs								$4,955,447

Notes:

1. Historical upgrade costs from 2011-2018 are from the previously submitted Load Research Reports. The data for the 2011-2012 report is from July 2011 to October 2012. The data for the next five reports, ending with the 2016-2017 report is from November to October of the following year. Data for the 2017-2018 report is from November 2017 to December 2018. Historical upgrade costs from 2019 from the previously submitted EV Charging Infrastructure Cost Report. Data for the 2019 report is from January to December.

2. In preparing this report, SCE identified an error in its 2019 Non-Pilot/Program Commercial Charging Infrastructure. SCE updated two figures from its original submission to reflect the correct data. Specifically SCE revised the figures in the 2019 report, from $543,539 to $2,814,530 Total Distribution System Costs Incurred by Utility for Upgrades and from $194,221 to $358,083 Total Service Line Costs Incurred by Utility for Upgrades (the total project count increased from 25 to 65). These cost totals do not include separate meter costs (not tracked in 2019).

ATTACHMENT 3

VII. Attachment 3 – SDG&E

SDG&E

Table 1 (SDG&E)

Number of EVs forecasted in IOU Service Territory

		Light-Duty	Medium/ Heavy Duty
Actual:	2011		
	2012	2,125	
	2013	4,400	
	2014	11,500	
	2015	18,000	
	2016	22,040	
	2017	26,498	
	2018	34,833	
	2019	49,585	
	2020	61,363	
Forecasted:	2021	57,820	N/A
	2022	64,436	N/A
	2023	71,051	N/A
	2024	77,667	N/A
	2025	84,283	N/A
	2026	90,899	N/A
	2027	97,515	N/A
	2028	104,131	N/A
	2029	110,746	N/A
	2030	117,362	N/A

IOU Comments:

Light-Duty historical / actual counts:

Historical EV counts are based off the EV count communicated in the load research report for that year.

Light-Duty forecasted counts:

SDG&E's EV forecast is the expected growth in the SDG&E service territory without the influence of SDG&E's EV programs at each year end. The forecasted vehicle count may be overstated due to a significant growth in EVs in 2018 and 2019.

Medium/ Heavy-Duty forecasted counts:

SDG&E has not yet completed its Medium / Heavy-Duty EV forecast.

Table 2 (SDG&E)

2020 EV-related Upgrade Costs		Residential Charging Infrastructure	Non-pilot/program Commercial Charging Infrastructure
Site Costs ($)	Design costs		
	Trenching and site excavation		
	Separate meter costs	$1,933	$5,377
	Permitting costs		
	Total Distribution System Costs Incurred by Utility for Upgrades	$52,172	$99,471
	Total Service Line costs Incurred by Utility for Upgrades	$44,954	$5,547
	Total Utility side costs		
	Total Customer Costs	$3,563	$73,404
	Other construction costs		
	Projected ongoing maintenance costs for utility-side infrastructure		
Support Activities ($)	Project management		
	Customer outreach (labor)		
	Marketing and education materials		
	Other costs		
Other	Total number of charge ports installed		
	Amount of new capacity resulting from project (kW)		

Key:	
	Data not available to report
	Data not available to report in 2020, but utilities will begin tracking for future reports

IOU Comments:

Table 3 (SDG&E)

2020 EV-related Upgrade Costs		Pilot/Program Commercial Charging Infrastructure					
		Light Duty Vehicle Infrastructure			Medium and Heavy Duty Vehicle Infrastructure		
		L2 Chargers - Multi-Unit Dwellings	L2 Chargers - Non-Residential LDV	DCFC - LDV [1]	Small sites: <500 kW	Medium Sites: 500 kW - 3 MW	Large Sites: >3 MW
Site Costs ($)	Design costs			8,174	41,998		
	Trenching and site excavation			612,702	374,022		
	Separate meter costs						
	Permitting costs						
	Total Distribution System Costs Incurred by Utility for Upgrades						
	Total Service Line costs Incurred by Utility for Upgrades						
	Total Utility side costs			227,503	175,829		
	Total Customer Costs						
	Projected ongoing maintenance costs for utility-side infrastructure						
Support Activities ($)	Project management			18,111	13,159		
	Customer outreach (labor)			5,394	7,249		
	Marketing and education materials						
	Other costs			66,512	17,711		
Other	Total number of charge ports installed			88	10		
	Amount of new capacity resulting from project (kW)			960	400		

Key:	
	Data not available to report

IOU Comments:
1 Any site that has a DCFC, even if L2 chargers are also installed, will be captured in this DCFC group

Table 4 (SDG&E)

		2012-2013	2013-2014	2014-2015	2015-2016	2016-2017	2017-2018	2019[2]
Historical Upgrade Costs[1]	Total Distribution System Costs Incurred by Utility for Upgrades	4,089	0	0	0	0	0	124,572
	Total Service Line costs Incurred by Utility for Upgrades	27,952	0	1,876	2,326	2,009	15,113	23,535
	Total Customer Portion of Utility Costs Covered by the exemption	32,041	0	1,876	2,326	2,009	15,113	2,046

IOU Comments:
[1] Historical upgrade costs from previously submitted Load Research Reports for periods 2012-2018
[2] 2019 historical upgrade costs based on actual costs incurred for customer upgrade jobs completed in 2019.